

BRITISH COLUMBIA UTILITIES COMMISSION

Commission Information Request No. 1 to British Columbia Hydro and Power Authority ("BC Hydro")

April 13, 2005

BC Hydro March 2005 Resource Expenditure and Acquisition Plan ("REAP")

1.0 Reference: 2005 REAP, Tab 1, p.1-2

The Plan states that the Resource Options Report ("ROR") is part of the 2006 REAP approval process and not part of this REAP filing. It further states that this REAP is the last element in a planning cycle which formed part of the 2004/05 to 2005/06 Revenue Requirements Application ("RRA") and the 2004 Integrated Electricity Plan ("IEP").

Please explain the significance of an IEP, ROR and REAP in the planning cycle for resource planning and please comment on the purpose of this filing.

2.0 References: 2005 REAP, p. 1-4, Table 1-2, and 2004 REAP, Table 1, p. 2; Tab 4, p. 4-18 Table 4-5

The DSM expenditures in the 2004 REAP for F2006 are \$97.4 million. The change between the 2004 REAP and the 2005 REAP is +\$30.1 million. The REAP states that the increase in expenditures from the 2004 REAP is primarily attributable to a shift in the timing of the Canfor load displacement project from F2005 into F2006. The energy efficiency electricity savings are also higher than indicated in the 2004 REAP.

- 2.1 Please provide the cross-reference in the 2004 REAP for the DSM forecast expenditures of \$97.4 million for F2006.
- 2.2 There is a difference of \$3.4 million in F2006 expenditures between the 2004 REAP PowerSmart line item and what is reported as the 2004 REAP DSM expenditure in the 2005 REAP. Please explain this difference.
- 2.3 In the RRA proceeding, it was revealed that the difference between actual and forecast DSM expenditures in F2004 is approximately \$54 million (RRA Decision pp. 198-201). Is this high degree of uncertainty in forecasting program costs carried over to the current REAP? Please explain.
 - 2.3.1 Please explain the discrepancy in F2005 expenditures as shown in Table 4.5 (\$55.927 million) and Appendix A Table 5 (\$74.693 million).
- 2.4 Table 1-2 shows a change of +\$30.1 million in DSM expenditures in the 2005 REAP from the 2004 REAP.
 - 2.4.1 Please provide the original and revised scope, budget and schedule for the Canfor load displacement project.
 - 2.4.2 Please describe what proportion of the \$30.1 million can be attributable to the shift in timing of the Canfor load displacement project from F2005 to F2006.
 - 2.4.3 Please comment on the increase in expenditures that is not related to Canfor.

2.4.4 If the increase in DSM expenditures in F2006 is due largely to the shift in timing of the Canfor project, please confirm that there is a corresponding decrease in the F2005 DSM expenditures. Please provide a comparison of the planned and actual 2004/05 Total BC Hydro Cost in a format similar to the column in RRA Volume 2, Appendix I, Table 4.5.

2.5 Table 4-2 shows a change of +19.1 million in the DSM F2007 expenditures in the 2005 REAP from the RRA. Please explain the variance with detailed analysis.

3.0 Reference: 2005 REAP, Tab 2, Resource Planning, p. 2-6; p. 2-37

BC Hydro's load forecasting activities centre on the production of a number of term-specific and location specific forecasts of energy sales and peak demand requirements. BC Hydro will conduct a study to gauge the impact of stepped rates on load forecasting models.

3.1 Although the completion date of the study is targeted for Q3 F2006, has BC Hydro finalized the forecasting methodology on assessing the impact of stepped rates and time-of-use rates for the transmission voltage customers on RS1821?

3.2 If the response to the above question is yes, please provide a description of the forecasting methodology for assessing the impact of stepped rate and/or TOU rate on the load forecasts. If BC Hydro has not yet finalized the methodology, please advise when it will be available for review.

4.0 Reference: 2005 REAP Tab 2, Resource Planning, p.2-8; Charts 2-1, 2-2; Appendix D p.22 Table 6.1

For 2004/05, the 2004 Load Forecast is above the 2003 Load Forecast by 1,050 GWh. For 2014/15, the 2004 Forecast is 1,171 GWh above the 2003 Forecast, while for 2023/24 the 2004 Forecast is 2,623 GWh above the 2003 Forecast.

4.1 In the legends to Charts 2-1 and 2-2, please explain what DSM includes or excludes.

4.2 Please provide the data used to create Charts 2-1 and 2-2 in tabular format.

4.3 Please present a comparison of the gross energy demand forecasts and the peak forecasts from the 2003 and 2004 Load Forecasts for the years F2006 to F2009, F2011 and F2014. Please show the comparison forecasts for Before Power Smart and With Power Smart.

4.4 Please break down the response to IR 4.3 by Sector: residential, commercial and industrial sales.

4.5 Please break down the response to IR 4.3 by region.

4.6 Table 6.1 in Appendix D shows that for the year 2004/05, the 2004 Load Forecast With Power Smart is 1,207 GWh above the 2003 Load Forecast. Please reconcile this figure with the 1,050 GWh stated on page 2-8. For the year 2014/15, please reconcile the respective figures of 1,328 GWh and 1,171 GWh and for the year 2023/23, please reconcile the respective figures of 2,780 GWh and 2,623 GWh.

4.7 In the With Power Smart forecasts in IR 4.3, how much of the higher load in the 2004 Load Forecast (as compared to the 2003 Load Forecast) is due to socioeconomic factors and how much is due to a shortfall in Power Smart and/or DSM savings?

5.0 Reference: 2005 REAP Tab 2, Resource Planning, p. 2-10; Appendix D p. 26 Table 6.5

For 2004/05, the peak demand including DSM in the 2004 Load Forecast is above the 2003 Load Forecast by 325 MW. For 2014/15, it is 141 MW higher and for 2023/24 it is 142 MW higher.

In Table 6.5 in Appendix D, it is shown that for the year 2004/05, the 2004 Load Forecast is 346 MW above the 2003 Load Forecast. Please reconcile this figure with the 325 MW stated on page 2-10. Please also provide reconciliation for 162 MW and 141 MW for the year 2014/15 and reconciliation for 142 MW and 163 MW for the year 2023/24.

6.0 Reference: 2005 REAP, p. 2-15, Table 2-4

“Several turbine runner projects that were previously planned are deferred beyond the REAP test period.”

Please provide an economic impact analysis for each turbine runner project that has been deferred, including the impact of foregone energy gains from increases in runner efficiency. Please provide this in spreadsheet format showing annual and total present value effects.

7.0 Reference: 2005 REAP, Tab 1, p. 1-1, and Tab 2, Resource Planning, p. 2-7 Tables 2-2 & 2-3; Appendix D Chapter 12

7.1 Page 2-5 states that only the Energy Efficiency programs are to be continued under Power Smart whereas Load Displacement programs are now separated from Power Smart. Have the text and tables on potential Power Smart savings in Chapter 12 of the 2004 Load Forecast been updated to reflect the new definition of Power Smart in the 2005 REAP? If no, please explain why.

7.2 In Section 2.3.1.1 on page 2-12, the Plan states that all committed Load Displacement projects are included in the load forecast and netted from the gross demand. Please provide the cross reference in Appendix D where the load displacement effects are included in the load forecast.

7.3 The Plan states that DSM initiatives are subdivided into energy efficiency programs and load displacement programs. Please explain why the summary tables A8.1 to A8.6 in the Electric Load Forecast do not incorporate savings from the Load Displacement programs even though these programs are described as part of the DSM initiatives.

8.0 Reference: 2005 REAP, p. 2-7

“This capacity-based peak reduction action item is to identify and estimate the potential for DSM to reduce BC Hydro’s peak load in milestone years F2011 and F2016. BC Hydro will evaluate DSM capacity options to address capacity constraints on the system.”

Please provide the schedule for completing the identification process, and a scoping document for the task, if it has been produced.

9.0 Reference: 2005 REAP Appendix D, p. 30

The weather normalized use rate is at 10,800 kWh. An estimated 20 per cent of BC Hydro’s residential accounts are heated electrically, and on average, these accounts require about 14,700 kWh.

- 9.1 What is the average consumption per account for 2004/05 for all (i.e., with and without space heating) residential sales customers?
- 9.2 What is the median consumption per account for 2004/05 for all residential customers?
- 9.3 Please provide a table showing the distribution of consumption per customer account among residential customers for 2004/05.

Use per Account (kWh/year)	Frequency Distribution
(the breakdown below is for illustrative purposes only, BC Hydro to refine in Response to IR)	
< 3,000	
3,001 – 6,000	
6,001 – 9,000	
9,001 – 12,000	
12,001 – 15,000	
15,001 – 18,000	
> 18,000	

- 9.4 Please comment on the likely characteristics of end use for those residential households consuming unusually high consumption per account.
 - 9.4.1 Could grow-operations be captured by the consumption per account analysis?
 - 9.4.2 Please comment on the historical load growth and provide an estimate of the load growth for the segment of unusually high use per account.

10.0 Reference: 2005 REAP Appendix D p. 18 Table 5.3

- 10.1 With the divergent future growth rates expected for the different customer segments, does BC Hydro expect a load duration curve for F2015, the year when a capacity deficit is expected (Appendix F, Table 2), to be quite different from the current curve?

10.2 Please provide the load duration curve for 2004/05 and the future load duration curve for F2015.

11.0 Reference: 2005 REAP, p. 2-21; p. 3-62

“Revelstoke 5 is a low cost source of 480 MW of dependable capacity with an associated 120 GWh of firm energy that would be available to meet load growth.”

- 11.1 Please provide the spill record for Revelstoke over the last 10 years, and correlate this against the ability to create 120 GWh of incremental firm energy at Revelstoke.
- 11.2 Please provide the project milestone schedules from the 2004 RRA period that showed an F2009 achievable in-service date, and the most recent one for the F2011 in-service date, and please describe the issues that have caused the achievable in-service date to be now two years later.
- 11.3 With consideration to the streamflow record at Revelstoke, please explain BC Hydro’s policy for assigning firm energy to large hydroelectric facilities.
- 11.4 The REAP states on page 3-62 that Generation gas determined that the optimum sequence is for Revelstoke 5 to proceed before Mica 5. Please describe the reasons for the conclusion that the optimum sequence is for Revelstoke 5 to proceed first.

12.0 Reference: 2005 REAP, Tab 2, Resource Planning, p. 2-21; p. 2-14

In Section 2.5.2, BC Hydro distinguishes Load Displacement projects from supply options in that these projects do not involve a sale of electricity to BC Hydro and that the customers’ core business is not electricity generation.

- 12.1 What are the necessary conditions for the projects to be categorized under Load Displacements?
- 12.2 If, for example, there had been no LTEPA with Alcan, which is categorized under supply options in Section 2.3.1.4, would such a resource be considered Load Displacement?

13.0 Reference: 2005 REAP, p. 2-24, Table 2-5

Please propose a method to separate the costs of Revelstoke 5 so that a cost can be placed on each of firm capacity and firm energy associated with the project.

14.0 Reference: 2005 REAP, p. 2-29

“BC Hydro participates in a multi-party initiative comprised of representatives from the IPP industry, Powerex, BCTC and the Government of British Columbia to proactively address IPP development issues and opportunities.”

Please describe the multi-party initiative referenced above, the issues and opportunities it is intended to address and the current status of the initiative.

15.0 Reference: 2005 REAP, p. 2-31

The 2005 REAP states on page 2-31 that “BC Hydro will update cost estimates for repowering.” and that “BC Hydro has completed an economic analysis of Burrard. BC Hydro is managing O&M and capital expenditures at Burrard to support the plant being able to provide capacity to 2014.”

15.1 Please provide the summary of economic analysis referenced above.

15.2 Please provide the updated repowering cost estimates and detailed scopes.

16.0 Reference: 2005 REAP, Tab 2, Resource Planning, p. 2-37; p. 4-4; p. 4-34

A study of the industrial sector was carried out and completed in F2004. The Plan also states that a third category of DSM programs, Peak Reduction, has been created to recognize a possible new line of initiatives but no new Peak Reduction programs are being proposed in this REAP.

16.1 Please describe the industrial sector study and comment if capacity-based peak reduction potential is included in this study. Please provide a copy of the study.

16.2 Even though no peak reduction programs have been proposed in this REAP, have the associated peak savings from the Load Displacement programs been included in the December 2004 Forecast?

16.3 When will the report on the inventory of DSM peak reduction potential in residential and commercial sectors be available?

17.0 Reference: 2005 REAP, Tab 2, Resource Planning, p. 2-39; Appendix D, p. 50

The Plan states that the impact of the change in design temperature is reflected in the most recent load forecast, i.e., December 2004. The most recent 30 years of weather data were used to derive the design temperature of -5.3 degrees Celsius for the system.

17.1 To what extent is the difference in peak demand forecasts from the two sets of forecasts (Dec 2003 and Dec 2004) for F2006 and F2007 a direct result of the change in design temperature and a recalibrated measurement on sensitivity to temperature? Please provide the analysis in detail.

17.2 Please give the 30-year time period that was used to derive the design temperature of -5.3 degrees for the System.

18.0 Reference: 2005 REAP, Tab 2, Resource Planning, Charts 2-3, 2-4

Please comment if associated reserve margins of energy and peak demand have been included in the charts showing demand/supply outlook.

19.0 Reference: 2005 REAP Appendix C p. 1; Appendix D, p. viii

The Electric Load Forecast report states that the Reference Forecast includes the assumption that rates will be constant in real terms for the balance of the forecast period post-F2005. In the Load Displacement Plan, it states that the assumed rate increase for F2006 is 0% and for F2007 and all subsequent years, the assumed rate increase is 1% per year.

Please provide the reasons for using different assumptions in the Load Displacement Plan.

20.0 Reference: 2005 REAP, Tab 2, Resource Planning, p. 2-21

The Plan states that Load Displacement projects differ from Energy Efficiency projects in that their primary driver is on-site generation (demand side of the revenue meter).

Are there instances where Load Displacement projects have exceeded self-sufficiency? If yes, how is surplus energy treated in (a) BC Hydro's integrated network? (b) the cost and benefit analysis for the Load Displacement Program?

21.0 Reference: 2005 REAP, p. 2-34

"BC Hydro has requested that BCTC preserve the earliest in-service date for the 230 kV AC submarine transmission (ARN-VIT) cables."

What is BC Hydro's understanding of the current earliest in-service date (month and year)?

22.0 Reference: 2005 REAP, p. 2-35

"BC Hydro conducted review of several jurisdictions across North America and their approach with respect to smaller projects."

Please provide relevant BC Hydro reports that document the results of the review.

23.0 Reference: 2005 REAP, p. 2-41

Please provide summaries of the current contingency plans.

24.0 Reference: 2005 REAP, p. 2-42 BC Hydro's 2004 NITS Application to BCTC

Please provide a copy of the BC Hydro 2004 NITS Application to BCTC.

25.0 Reference: 2005 REAP, p. 2-44 Request for Approval of Expenditures

Please explain BC Hydro's rationale for requesting approval of a four-year estimate of expenditures every year, considering that the estimates for future periods will necessarily change depending on contract terms and changes in natural gas prices.

26.0 Reference: 2005 REAP, p. 2-45 Acquisition Plan, proposed F2006 Call for tenders.

Will BC Hydro establish a price cap for the call? If so, when will BC Hydro establish the level of

any such price cap and when will it be made available before hand to bidder? Please justify why a price cap is or is not appropriate. Should the Commission approve the level of the price cap as part of its approval of the call process and documents? If BC Hydro believes the following question is commercially sensitive, please provide the answer in confidence under separate cover.

How will BC Hydro determine the price limits for the above call?

27.0 Reference: 2005 REAP, Appendix E, p. 3.

BC Hydro has indicated in Appendix E that it would receive comments to its draft Call for Tender and Electricity Purchase Agreements and decide on the form for these documents by June 2005. In its letter of March 29 to the Commission BC Hydro now proposes to file an Overview Document, the proposed Terms and Conditions Document and the Proposed Mandatory F2006 Call Criteria and Evaluation Methodology by May 17, 2005.

Does BC Hydro now propose that the Commission review and approve these documents as part of the REAP review or does BC Hydro still intend to file a revised form of the document in June for Commission approval before BC Hydro issues the Call for Tenders?

28.0 Reference: 2005 REAP Appendix D Tables A8.1 – A8.6

Under BCTC's Open Access Transmission Tariff ("OATT"), a retail access customer becomes a customer of BCTC and ceases to be a customer of BC Hydro.

- 28.1 Are future demands of retail access customers included in the future forecast scenarios in the 2005 Load Forecast?
- 28.2 If the demands are included in the annual forecasts, can the demands be separately identified?
- 28.3 If the demands are not included in the annual forecasts, are they being recognized in other BC Hydro load forecast models or publications?

29.0 Reference: 2005 REAP, p. 3-1 Re: Substation Distribution Assets (SDAs)

BC Hydro states that it is BC Hydro's responsibility to obtain regulatory approval for expenditures related to the SDAs.

- 29.1 Please reconcile all projects and expenditures in BC Hydro's REAP filing with those listed in BCTC's Capital Plan Filing for the Period 2006 to 2015. Please provide a table showing all projects listed in BC Hydro's filing and their estimated costs, compared to all projects shown in the BCTC filing with estimated costs. Where there are differences please explain why.
- 29.2 Please explain the process BC Hydro follows when it is constructing the list of projects to be included in its REAP filing. Please explain how BC Hydro determines the need for and the most appropriate solution to fill that need for any given project. How does BC Hydro co-ordinate the planning and project parameters with BCTC? In cases of differing opinions as to the most appropriate solution how are decisions made?

30.0 Reference: 2005 REAP, p. 3-2, Table 3-1

Although the increase in vehicle expenditures from F2005 to F2006 has been described as a deferral of some F2005 costs into F2006, costs in F2007 are still greater than in F2006. Please explain the further increase in F2007.

31.0 Reference: 2005 REAP, p. 3-2 Distribution System Improvement Expenditures

What is referred to in BC Hydro's statement that it is facing increased Operation Pressure? Please give examples of where this pressure is causing increased costs.

32.0 Reference: 2005 REAP p. 3-4

BC Hydro states that it is not seeking approval for the precise amount associated with each project or group of projects.

32.1 Please define what level of accuracy is associated with the estimates for any given project in the REAP document. What does BC Hydro mean by "Precise Amount"?

32.2 Please list all projects for which BC Hydro intends to file a CPCN. Please also provide a schedule for when BC Hydro intends to file these projects.

32.3 Please describe the criteria and rationale for BC Hydro's intended CPCN filings.

32.4 Throughout the REAP document there are a number of projects listed with estimated costs, which are not yet finalized (e.g. the John Hart redevelopment project, GMS turbine upgrades etc.)

32.4.1 From tables 3-15, 3-16 and 3-22 please identify the projects which are not yet finalized. For those projects please describe the range of possible costs associated with each one.

32.4.2 If the projects are not finalized what is BC Hydro seeking approval for?

33.0 Reference: 2005 REAP, p. 3-6, Common Desktop Services

BC Hydro states that the new CDS #3 is expected to position BC Hydro for the next four years.

33.1 For how long has the present (CDS #2) been in service?

33.2 What is the typical life span for these types of platforms?

33.3 Please describe BC Hydro's longer-term strategy for the delivery of these types of services.

34.0 Reference: 2005 REAP, p. 3-15, p. 3-30 GMS, Peace Canyon Stator Replacements

34.1 Please provide a description detailing the need, cost, timing and alternatives for the Peace Canyon Stator Replacement Projects.

34.2 BC Hydro states that for GMS there is a parallel investigation to upgrade the turbines of units 1 to 5 and that the upgrade project would coincide with the Stator Replacement.

Please provide any executive level planning reports which have examined the strategy for GMS, Peace Canyon and Mica Generating stations. Please also provide any more detailed reports used for the justification and approval for these projects to senior managers.

35.0 Reference: 2005 REAP, p. 3-15, and p. 3-17

On page 3-15 the REAP states that “At Peace Canyon and GM Shrum, the condition of the generators of units 1 to 4 are such that they have an unacceptably high risk of major failure. The plan is to replace the four stators at Peace Canyon, one per year by F2010. For GM Shrum, the plan is to also replace the units 1 to 4 stators, one per year, by F2011.”

On page 3-17 it states that “One of the major capital initiatives in the Columbia Region is to replace each of the four stators at Mica.”

35.1 Please provide, for each facility, the economic analysis that was performed to purchase two spare stators and windings for each plant and run the units to failure, and a comparison against the other options.

35.2 Please provide, for each facility, the technical analysis that compared the above option against the other options.

36.0 Reference: 2005 REAP, p. 3-15, Table 3-7

Please explain the differences between “average energy” and “firm energy”. Does BC Hydro apply a firming factor to translate average energy into firm energy, and if so, what considerations go into determining that firming factor?

37.0 Reference: 2005 REAP, p. 3-21; p. 3-9

“BC Hydro Generation is continuing to negotiate with First Nations to resolve historic grievances for the Peace and Bridge River systems.”

37.1 Please describe BC Hydro’s scope containment and initiative completion strategies that would allow this activity to be considered a capital investment rather than an operating expense.

37.2 Does BC Hydro have other First Nations issues with which it is or will be conducting negotiations on (e.g. for other generation or transmission related land issues)? If so what is BC Hydro’s estimate of the costs associated with negotiations for the total number of issues and what period is estimated for completing those negotiations?

37.3 Does the \$51.7 million dollars for the total cost of negotiations represent negotiation costs only for the Peace and Bridge River systems? Please provide a cost breakdown of those costs and explain what activities are associated with them.

37.4 Elsewhere, BC Hydro has described these costs as a preferred alternative to litigation. Please provide on a confidential basis, under separate cover, any studies which support this conclusion.

BC Hydro states that the overall increase of \$27 million for F 2006 is partially attributable to increase in expenditures associated with negotiating with First Nations.

37.5 Please describe how much of the increase is attributable to increases in negotiating with First Nations. In addition, explain why those increases are necessary.

38.0 Reference: 2005 REAP, p. 3-27

Please supply the benefit-cost analysis of the alternatives considered for the Cheakamus G1 & G2 Generator Replacement.

39.0 Reference: 2005 REAP, p. 3-30, GM Shrum G1 to G4 Stator Replacement

“For units G1 and G2, the option of core repair and winding replacement was investigated. However, this was rejected because the cost savings would be small and the life of new windings installed on a repaired core would be much shorter than that for new windings installed on a new core.”

39.1 Please provide the detailed technical analysis that supports the expectation of decreased life expectancy of new windings on an old core.

39.2 Please provide the economic analysis of performing successive rewinds from prematurely failed windings compared with the selected option.

40.0 Reference: 2005 REAP, p. 3-31, GM Shrum Transformer Replacement Stage 2

40.1 Please provide the economic analysis comparing options b and c with the selected option.

40.2 In BC Hydro's installed base of transformers of over 50 MVA in size, in the past 30 years, how many units have failed in service, and of those failures, how many involved uncontrolled release of oil into the environment? Does BC Hydro have access to similar statistics for Canadian or WECC utilities?

40.3 What oil containment facilities and measures are in place for the transformers at GM Shrum?

41.0 Reference: 2005 REAP, p. 3-33, John Hart Modernization Study

When is the feasibility study expected to be complete? Does BC Hydro intend to file this study with the Commission? Will BC Hydro be required to seek other regulatory approval for this project (i.e. environmental, fisheries or water licensing)?

42.0 Reference: 2005 REAP, p. 3-35 Mica G1 to G4 Stator Replacement. (Similarly GMS and Peace Canyon)

BC Hydro notes that the problem with core waves was first noticed in 1978.

42.1 What is the condition of the remaining stators in each of these plants? Will the remaining stators also need to be replaced at some time and if so when?

42.2 What is the cause of these Core Waves (i.e. are they caused by design deficiencies, operating practices or some other reason)?

42.3 Are there maintenance practices or more aggressive refurbishment practices which could prevent these failures in the future? If so please describe what can be done and if they are cost effective.

42.4 At lines 13-17 on page 3-35, the REAP states that the generators have experienced problems with core waves that have resulted in progressive damage to the stator core. Will the replacement of the stators deal with the core waves?

43.0 Reference: 2005 REAP, p. 3-35, 3-37, p. 3-39 Mica G1 to G4 Exciter Replacement, Governor Replacement

BC Hydro describes these programs as part of a 10-year maintenance strategy to proactively replace critical components before they completely fail.

43.1 Please describe any other projects which fall within the same criteria.

43.2 Does BC Hydro employ this strategy on other generation stations? If so, please describe the programs associated with other stations.

43.3 Has BC Hydro produced any analysis to verify the financial benefits of these strategies? If so, please file them. If not, please explain the basis for these strategies and file the analyses.

43.4 What is the life expectancy of the new exciters?

43.5 What is the life expectancy of the new governor control systems?

44.0 Reference: 2005 REAP, p. 3-42 Coquitlam Dam Seismic Improvements

44.1 Please provide the executive summaries used for the justification of this project.

44.2 Will the costs of this dam improvement be shared with the GVRD? If not, what responsibility does the GVRD have for this dam and the use of the reservoir?

44.3 Is the size of the reservoir being altered? If so, please describe how and if any additional benefits for increased water storage were considered?

45.0 Reference: 2005 REAP, p. 3-44 Keenlyside – Concrete Dam Seismic Improvements

45.1 Does this project have anything to do with the recent leaks in the intake structures for the CPC generation station? If not please explain what this project is and what other upgrades are currently under review.

45.2 What is the status of repairs to the intake structures at the Keenlyside generation station? Please describe the work required. Who has responsibility for this work? If the responsibility lies with CPC how does BC Hydro ensure that the integrity of the Dam is not compromised?

46.0 Reference: 2005 REAP, p. 3-47 Mica Stability Assessment of the Little Chief Slide

46.1 Please describe the risk assessment that BC Hydro has done on this slide. What options does BC Hydro have to mitigate the risk.

46.2 BC Hydro has been aware of this slide since 1969. Why has a detailed analysis of this slide not been done already?

46.3 Please explain what is involved in the present study and why it will take 4 years to complete.

47.0 Reference: 2005 REAP, Tab 3, Capital Plans, pp. 3-48, 3-49

47.1 The REAP states on page 3-48 that the capital expenditures in F2006 and F2007 are to complete the necessary studies to select the preferred alternative and to proceed with preliminary design.

To what extent will the studies include discussion of the lower cost alternative identified in the 2004 REAP and the reasons why that lower cost alternative is considered now to be unacceptable?

47.2 On page 3-49, at lines 4-5, the REAP states that the cost estimates identified in the table relate to a rebuild and contain a large degree of uncertainty. To what extent will the studies reduce the uncertainty of the cost estimates?

48.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-52

The REAP states at page 3-52 that the updated costs are forecast to be higher than previously estimated.

What are the reasons for the forecast costs to be higher than previously estimated?

49.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-53

BC Hydro states at page 3-52 that piping risk is related to the performance of the embankment dam and there have been unusual instrumentation readings.

49.1 Describe the piping risk for the Strathcona Dam.

49.2 Please also describe the “unusual instrumentation readings” and the implications of those readings for the piping risk.

50.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-54

On page 3-54 BC Hydro states that several alternative sizes were considered and that the incremental unit cost of energy declines in moving from a 5 MW to a 17 MW project and increases with project size thereafter.

Please provide the economic analysis comparing the various capacity alternatives with the selected option, along with the unit cost of energy and summaries of supporting estimates for capital costs of each alternative.

51.0 Reference: 2005 REAP, p. 3-54 Growth Projects

Please provide the business case analysis for all growth projects and describe how BC Hydro prioritizes each project.

52.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-56

The REAP states that BC Hydro's unit cost of energy for the Cheakamus Turbine Upgrade, based on a total energy gain of 46 GWh/yr, is \$28/MWh, and that this cost is economic compared to the cost of new energy supply.

What is BC Hydro's current estimate of the cost of new energy supply? What is that estimate based on? Please provide any study or report that supports that estimate.

53.0 Reference: 2005 REAP, p. 3-56, Cheakamus Turbine Upgrade

Will the runner replacement trigger the need or opportunity for the replacement of other ancillary equipment (governors, exciters, switchgear, protection and controls, etc.)? If so, please provide project scopes and cost estimates for these related activities.

54.0 Reference: 2005 REAP, pp. 3-57, 3-58 GM Shrum Capacity Increase

54.1 Please provide detailed project scope descriptions for the capacity increase projects for Units 6, 7 and 8 at GM Shrum.

54.2 Please provide a brief line item reconciliation of the anticipated amount and schedule of investigative costs for the scope that underpinned the 2004 RRA costs against the scope in the 2005 REAP, specifically identifying the drivers for the almost five-fold cost increases.

54.3 What total increase in plant capacity would result from capacity upgrades on G6, G7 and G8?

54.4 If the total increase in plant capacity arising from the upgrades under consideration exceeds 90 MW, is BC Hydro intending to seek an amendment to its water licence to ensure that the extra capacity will be fully useable? If so, when will BC Hydro be seeking such an amendment? If not, why not?

55.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-59

The GM Shrum Unit 1 to Unit 5 Turbine Upgrade is expected to achieve an efficiency gain of about 2%, (i.e. an energy gain of approximately 125 GWh/yr for the five units).

Will there also be a capacity gain associated with the upgrade of the turbines for units G1 to G5? If so, how much will it increase?

56.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-65

BC Hydro states at page 3-65 that the Information Technology ("IT") capital expenditures for F2006 increased \$5 million as a result of expenditures in the F2005 IT capital plan being deferred for one year.

Is the \$5 million expenditure planned for 2005 related to the deferral of expenditures in the F2005 IT capital plan, currently included in the F2005 revenue requirement? If the March 2005 REAP is approved as filed, will the same planned \$5 million expenditure be included in the F2006 revenue requirement? If not, how is it excluded from the F2006 Revenue Requirements?

57.0 Reference: 2005 REAP, p. 3-67 Table 3-19 Distribution Capital Changes from F2005 to F2006

Table 3-19 shows a change in SDAs from \$23.0 Million in F2005 to \$62.5 million in F2006 because of a transfer of SDAs from Transmission to Distribution. Does the \$23 million in F2005 represent only the SDAs which were the responsibility of Distribution? If so please provide a comparison for F2005 of all SDAs including those which were the responsibility of Transmission. If not, please explain the need for the increase from \$23 to \$65 million.

58.0 Reference: 2005 REAP, Tab 3, Capital Plans, pp. 3-67, 3-68

Table 3-19 shows a net increase of 17.6 Million for the F2005 Plan/YEF and \$55.1 million for the F2006 Plan due to Organizational Transfers.

58.1 To what extent do these increases result from changes in the classification of the costs or the departments which house the costs?

58.2 To the extent that these increases do result from changes in the classification of the costs or the departments which house the costs, please explain why the net change should not be zero if the costs are simply being transferred from one cost centre to another?

58.3 Please provide a table that reconciles the differences between the 2004 RRA and the 2005 REAP that arise from organizational changes in the classification of a cost or the cost centre that houses that cost.

59.0 Reference: 2005 REAP, p. 3-71, Table 3-20 and 2004 REAP, p. 2, Table 1

Please provide a breakdown of Table 1 of the 2004 REAP in the fashion of Table 3-20, and provide comments for changes greater than 5% of the 2004 REAP value.

60.0 Reference: 2005 REAP, p. 3-72, Performance Targets

60.1 Please explain in detail how feeder level improvements are evaluated to ensure they align with _____ over all performance targets.

60.2 Please describe BC Hydro's Distribution Performance targets and compare the target levels to _____ actual performance for the last 3 years.

61.0 Reference: 2005 REAP, Tab 3, Capital Plans, p. 3-73

In section 3.12.5, BC Hydro notes that the expenditures related to customer growth include the construction of distribution extensions, customer connections and customer driven improvements and relocation.

61.1 Please describe BC Hydro's method of forecasting these expenditures.

61.2 Please provide the actual expenditure per new customer for the past five years and the forecast expenditure per new customer for F2005 and F2006.

62.0 Reference: 2005 REAP, p. 3-76

“Chart 3-3 indicates the age profile of the Distribution poles, which is one of the major asset categories within the Distribution system, and is considered a good indicator of the age and useful service life of other asset categories within the system.”

62.1 Please explain which asset categories the Distribution pole age profile is a good indicator for, and how this relationship is established. If possible, please provide support for this analysis using industry data such as the PA Consulting Group data.

62.2 From the pole-testing program, what is the average age and profile of Distribution poles that are replaced for condition-driven causes?

63.0 Reference: 2005 REAP, p. 3-78

“Results of surveys completed by PA Consulting Group and EUCG Incorporated are presented below in subsections 3.13.3.1 and 3.13.3.2.”

Please supply any information from the above referenced PA Consulting Group and EUCG Incorporated surveys that was not provided in the 2004 RRA Proceedings.

64.0 Reference: 2005 REAP, p. 3-81, Table 3-22

Please identify which projects, if any, were not part of the capital expenditures presented in the 2004 RRA Proceedings, and which have changed in cost by more than 10%.

65.0 Reference: 2005 REAP, Tab 4, Demand Side Management, p.4-2 Table 4.1

65.1 Please comment if the OMA expenses in the 2005 REAP are identical to those in the 2004 REAP. If not, please explain the variances.

65.2 The RRA Decision determines that BC Hydro will file semi-annual DSM reports that will include detailed breakdown of OMA expenses. Please advise when the first semi-annual DSM report will be filed.

66.0 Reference: 2005 REAP, Tab 4, Demand Side Management, p. 4-12

The Plan states that Energy Efficiency Plan is reviewed annually. Is the latest report on the review of F2005 and the latest outlook available? If yes, please provide the review report. If no, please provide a summary of the analysis and conclusions of the annual review.

67.0 Reference: 2005 REAP, Tab 4, Demand Side Management, p. 4-15; p.4-27

The Plan states that self-generation optimization (SGO) projects from the industrial sector are more similar to energy efficiency than load displacement projects because the electricity savings result primarily from an efficiency improvement rather than from increasing system generation capacity. The Plan also states that large Energy Efficiency projects are included within the LPI process.

Please explain if the identification and selection of SGO projects are similar to the competitive processes designed to select Load Displacement projects.

68.0 Reference: 2005 REAP, Tab 4, Demand Side Management, pp.4-18, 4-19, 4-21, Tables 4-5, 4-6 & 4-7

Compact Fluorescent Lighting program has the highest Residential Sector expenditures at \$5.34 million and \$5.43 million respectively forecasted for F2006 and F2007. Please show the detailed calculation for the following:

68.1 levelized utility cost (\$/kWh) of 0.018, levelized TRC (\$/kWh) of 0.029 and levelized RIM cost (\$/kWh) of 0.069;

68.2 Benefit Cost ratios of 2.7 for UC, 1.7 for TRC and 0.7 for RIM;

68.3 Average rate increment (cents/kWh) of 0.0087;

68.4 Average cost per residential customer (\$/year) of 0.93.

69.0 Reference: 2005 REAP, Tab 4, Demand Side Management, p. 4-27

The LPI process uses a number of selection criterion, one of which is a simple payback equal to or greater than two years.

In the RRA proceeding, in Transcript Vol. 14 page 2338, lines 3-12, BC Hydro testified that the utility has replaced the two-year payback criterion with the internal rate of return and that the cap on the IRR for a load displacement program is 20 per cent. Please explain why BC Hydro dropped the IRR and revived the payback criterion in the 2005 REAP.

70.0 Reference: 2005 REAP, p. 4-31

The REAP states that "An evaluation template has been developed for customers to allow them to model the selection criteria and explore various bid scenarios." Please supply a copy of the evaluation template.

71.0 Reference: 2005 REAP Tab 4, Demand Side Management, p. 4-32, Table 4-8; Appendix C Table 1

Please reconcile BC Hydro's Cost for F2005 of \$22.960 million in Appendix C Table 1 and \$21.368 million in Table 4-8.

72.0 Reference: 2005 REAP, Tab 2, page 2-14

"Alcan currently supplies 140 Average MW (equivalent to approximately 1,225 GWh per year) to BC Hydro under the Long Term Energy Purchase Agreement (LTEPA). The term of the LTEPA extends until end of December, 2014, however, Alcan has issued a notice to recall the LTEPA starting January 2010."

72.1 Please describe Alcan's rights to recall the LTEPA before the end of term.

72.2 Does the recall of the LTEPA prior to full term trigger any other system planning or economic consequences?

73.0 Reference: 2005 REAP, Tab 4, p. 4-15

“While there are changes to the names of some programs (e.g., Commercial New Construction changed to High Performance Buildings), and the aggregation of programs in situations where multiple initiatives are pursuing a common strategy and/or market opportunity, (e.g., multiple residential Compact Fluorescent Light (CFL) programs), there are no new programs being proposed in the REAP.”

73.1 Please identify the programs that, although not new, have either changed in economic scope by 25%, or where the original target market sector has changed by more than 25% in either volume or composition.

74.0 Reference: 2005 REAP, Tab 4, p. 4-28

“Forecast cumulative electricity savings in F2012 are 146 GWh higher, reflecting the successful contracting of the Weyerhaeuser and Canfor Load Displacement projects and BC Hydro’s updated estimate of the remaining achievable Load Displacement potential in the province.”

74.1 Please provide the scope, budget and schedule for the Weyerhaeuser load displacement project.

74.2 Please provide details BC Hydro’s updated estimate of the remaining achievable Load Displacement potential in the province, including year of implementation, location, and opportunities for deferral of system capacity upgrades.