BRITISH COLUMBIA UTILITIES COMMISSION
Commission Information Request No. 1

British Columbia Hydro and Power Authority ("BC Hydro")
Project No. 3698360 – Order No. G-84-03
2004-05 and 2005-06 Revenue Requirements Application
and
British Columbia Transmission Corporation ("BCTC")
Application for Deferral Accounts

1.0 Reference: Application, Volume 1, Chapter 1, p. 1-9, Section 2.4, Trade Revenues

1.1 In order to provide a better understanding of the market in which Trade Revenues were the main reason cited for the sustainability of the rate freeze for the past ten years, please provide by year from F1994 through F2003:

- Streamflows as a percentage of average
- Annual hydro electric energy generation
- Net Annual surplus sales
- Revenues realized from surplus sales
- Powerex' net Trade Income plus a brief explanation of that Trade Income

1.2 **Reference: Volume 1, Chapter 1, Application overview**

For each year from F1994 through F2003, please provide the Powerex net Trade Income that BC Hydro used for its annual Budget, the difference between actual and Budget net Trade Income, and an explanation of significant variances.

1.3 **Reference: Volume 1, p. 1-15, Cost Drivers**

Please provide a cost summary of requirements needed to maintain the reliability of the system.

1.4 **Reference: Volume 1, Chapter 1, p. 1-18**

Please provide several examples of how BC Hydro measures and rewards superior performance through clear accountabilities.

2.0 Reference: Application, Volume I, Chapter 2, Consolidated Revenue Requirements and Financial Schedules

2.1 Page 2-2, Lines 10-11 and Table 2-1: With an equity base of $3042 million and $3120 million, the allowed ROE of 13.91 percent yields amounts of $423 million and $434 million for F2005 and F2006, respectively. Thus, with Net Income from Table 2-1 shown as $251 million and $221 million in F2005 and F2006, respectively, the respective revenue shortfalls appear to be $172 million and $213 million. Please explain the difference between these amounts and those referenced in lines 10 and 11.

2.2 Page 2-3, Table 2-2: Please indicate for Columns C and D whether or not an average expected value was used for the key variables used in establishing this table. Please provide an update to Column C and D for the following sensitivities (note that BC Hydro may wish to change the proposed sensitivities and/or the variability if they are felt to be inappropriate):

- Load variations due to weather variation (+/-2%)
- Streamflow variations (+/-5%)
- Market fluctuations (+/-10%)
- Fluctuations around Power Smart take up rates (+/-20%)
- Constraints or opportunities on the operation of Burrard that might result from the MLA review
- Other credible scenarios that might have an impact on customer rates

2.3 Page 2-3, Table 2-2: Please indicate what comfort the customer can take that the forecast Trade Income of $80 million for F2005 and $89 million for F2006 is as good as can be provided and please provide what sensitivities might impact this forecast and quantify the possible impact. Please provide an explanation of the differences between F2003 Actual, F2004 Forecast and F2005-F2006 Forecast.

2.4 Page 2-5, Table 2-4: Is the F2006 $20 million special BCTC dividend matched by a reduction elsewhere in the payment obligation to the province?

2.5 Page 2-6, Table 2-5: Are the "other utilities" revenues the Skagit River Treaty? If not, please explain.

2.6 Page 2-6, Table 2-6: What is the basis for Aquila's energy reduction from F2004 to F2005, and does anything prevent Aquila from taking more energy than forecast or plan? If so, explain.

2.7 Page 2-8, Table 2-8: Explain the statement in footnote 1 regarding "prior periods" and how the activities in prior periods affect the "Net Sales to Powerex – Future Use" in light of statements further in the application that no surplus hydro is forecast in F2005 and F2006. Are these periods year-over-year or something different? Should this mechanism be handled through the Trade Account? Why or why not? Also, explain the statement in footnote 5 regarding the foreign exchange gain on payables to Powerex, and explain why the settlement of these transactions isn't done simultaneously with the transaction with no timing difference on the foreign exchange between transaction and settlement. Explain why this also isn't addressed through the use of the Trade Account.

2.8 Page 2-10, Lines 10-13: Please provide OMA functional disaggregated cost of service levels.

2.9 Page 2-10, Lines 19-23: What portions of the $14 million increased net maintenance costs expended to maintain existing reliability levels are targeted at Generation, Transmission and Distribution assets, and what was the increase in this expenditure for F2004 over F2003? What maintenance costs are identified to improve on the existing reliability levels?

2.10 Page 2-16, Table 2-13: What projects have been abandoned or studies capitalized over F2003 and F2004, and which are forecast over F2005 and F2006?

2.11 Page 2-16, Lines 10 and 16-17: What are the three biggest generation asset additions driving the $6 million increase in depreciation, and what fundamental driver led to the reduced life expectancy of the Burrard Generating Station ("Burrard")? Show the depreciation amounts for Burrard for the last ten years, and the expected depreciation amounts to 2014.

2.12 Page 2-16, Section 3.7.1: Which of the identified increases are one-time, and which are sustained?

2.13 Page 2-22, Lines 21-23: The depreciation charges of $1 million could be indicative of a much larger capitalized amount. Please explain what addition to the asset base would drive this increased depreciation charge.

2.14 Page 2-23, Lines 12-13: Explain in detail the mechanisms leading to Net Sales to Powerex in F2005 and F2006 as shown in Table 2-8, page 2-8.

2.15 Page 2-48, Schedule A-8: Explain the source of the "other" revenues.

2.16 Page 2-49, Schedule A-9, Line 12: What exchange rate has been assumed for the cost of the market purchases? What efforts does BC Hydro make to protect against exchange rate fluctuations that might go against the customer?

2.17 Page 2-49, Schedule A-9, Lines 14 and 17: Explain any correlation between these line items. What components of each are fixed, and what are variable?

2.18 Page 2-49, Schedule A-9, Line 27: Please reconcile the IPP purchases for F2005 of 6598 GWh versus the sum of Tab 4, Tables 4-4 and 4-5 of 6568 and Tab 4, Table 4-11 of 6594.

2.19 Page 2-49, Schedule A-9, Line 29: Given the Transfer Pricing Agreement between BC Hydro and Powerex, why are the Market electricity purchases not shown as Net Purchases from Powerex for F2005 and F2006? What percentage of purchases is expected to be made out of Alberta and what out of the U.S.?

2.20 Page 2-49, Schedule A-9, Line 33: Receipt of Non-Treaty Storage in F2003 (Exchange net) appears to drive Market purchases and Purchases from Powerex. Please explain.

2.21 Page 2-49, Schedule A-9, Line 36: Please explain what "Net sales to Powerex" are in light of the fact that there are no surpluses shown in Tab 4, Table 4-11.

2.22 Page 2-49, Schedule A-9, Line 43: Given the average rate forecast for market purchases of 45.3 $/MWh in 2005 and 36.5 $/MWh in F2006 and given the reservoir filling of about 810 GWh in F2005 as indicated in Tab 5, page 5-4, would it not be more economic to defer filling until F2006 or is this a question of a timing differential for storage refill and market purchases? Please explain.

2.23 Page 2-49, Schedule A-9, Line 43: Please provide a market price forecast by month for F2005 and F2006 for both heavy and light load hours. Please provide a market price forecast for F2007 through F2013. From where do these market forecast originate and what evidence is there that provides some confidence that this particular forecast is the appropriate one to use for the purpose of this Rate Application? Please provide an overview of the WECC load/resource balance, including forecast resource additions versus load growth, for the next ten years and provide expectations for the surplus market.

2.24 Page 2-49, Schedule A-9: Please provide figures for F2005 and F2006 by month. Please provide graphically, for F2005, a load duration curve by hour for lines 26 through 33. For F2006, please provide lines 26 through 33 and lines 40 through 46 graphically with price on the "Y" axis and volume on the "X" axis.

2.25 Addendum 1 of the Vancouver Island Call for Tenders (the "CFT") sets out four pairs of gas and electricity price forecasts. Please use each of the four CFT electricity forecasts to calculate forecasts of the cost of Market Electricity Purchases (Tab 2, Table A-9, line 12) by month for F2005 and F2006.

2.26 Page 2-49, Schedule A-9: Please expand this table to provide F1994 through F2002 Actuals.

2.27 Page 2-69. Please describe the rationale for the allocation of DSM costs per note 1.

2.28 Page 2-79, Schedule D1-1, Line 13: Why has capitalized overhead increased so significantly from F2003 to F2004, while the capital expenditures have decreased significantly over the same time period?

2.29 For F1994 through F2004, how much Overhead was capitalized each year?

2.30 What was BC Hydro's Overhead capitalization policy for F1994, at the time of the Commission's last review of BC Hydro revenue requirements?

2.31 Please explain and justify any changes that BC Hydro has subsequently made to its Overhead capitalization policy.

2.32 Assuming the Overhead capitalization that was in effect for F1994 continued in effect, how much Overhead would have been capitalized each year from F1994 to F2006?

2.33 Page 2-80, Schedule D1-2, Line 2: Reconcile the IPP costs shown here versus lines 10 and 11 on Schedule A-9, and also against the values shown in Table 4-11.

2.34 Page 2-80, Schedule D1-2, Line 18: Correlate this line item to "Net sales to Powerex – Future Use" from Table 2-8 (page 2-8) and explain how and why this item is not considered part of the Trade Account.

2.35 Page 2-80, Schedule D1-2: Show how and where the values given in Table 4-1, or what portions, integrate into the values contained in Schedule A-9 and Schedule D1-2.

2.36 Page 2-80, Schedule D1-2: Explain in further detail the reference in Note 1 whereby water rental charges are manifested against Trade Income (rather than intersegment revenues).

2.37 Page 2-82, Schedule D1-4: Show F2006 in this schedule.

2.38 Page 2-92, Schedule E1, Line 4: Explain the source and rationale for costs and activities driving the increase in corporate allocations from F2003 to F2005**.**

3.0 Reference: Application, Volume 1, Chapter 3, BC Hydro Corporate Functions

3.1 Page 3-9 and 3-10, Section 4.2, Occupational Safety

The Application states that BC Hydro had contracted with DuPont Safety Resources to conduct a safety evaluation on the utility's safety performance. It also states that upon review of DuPont's findings, BC Hydro's executive identified the need for a renewed approach to safety.

Please provide details of the DuPont safety evaluation contract, including Terms of Reference, costs, in-house resources used (if applicable), and a copy of the final report of their findings. Additionally, provide details of the specific actions taken by BC Hydro pursuant to the recommendations in the report, as well as the utility's implementation costs to date by fiscal year, and projected costs in fiscal F2004, F2005 and F2006.

3.2 Page 3-9. Please also provide all BCH Safety statistics by function (Generation, Transmission and Distribution) for the past five years. These should also include safety statistics for all contracted work. Please also provide audit reports for the past five years.

3.3 Page 3-52. Please provide the objectives of BC Hydro's R and D program and a list of the projects designed to achieve those objectives. Please also provide the performance metrics for those programs.

3.4 Page 3-53. Please explain why $10 million have been budgeted for R and D while only $5.7 million is expected to be spent.

4.0 Reference: Application, Volume I, Chapter 4, Energy Supply Costs

4.1 Page 4-2, Table 4-1: Explain the linkages and allotments between lines 16 and 17 of Schedule A-9 and the Gas transportation and domestic transmission line item in Table 4-1.

4.2 Page 4-4, Lines 1-3: Provide a table and explanations detailing the differences between the cost of supplying energy and the consolidated cost of energy.

4.3 Page 4-2, Table 4-1, page 4-9 Table 4-3: Please provide the cost per MWh for each category of power purchases.

4.4 Page 4-9, Table 4-3: Under the various Energy Supply Agreements for the hydro resources, what portion of the energy capabilities is BC Hydro committed to take and what portion is the seller committed to supply? What, if any, are the penalties for failure to deliver the committed supply?

4.5 Page 4-9, Table 4-3: What terms are there in the Energy Purchase Agreements that might impact the proposed Heritage Deferral Account in addition to supply variability? Are the prices for Energy Purchase power at or less than the forecast market prices? Does the price of the various Energy Purchase Agreements escalate at inflation or some other defined index or by some other means?

4.6 Page 4-9, Table 4-3, Page 4-10, Table 4-4: If in F2005, the volume and consequent costs of Energy Purchase Agreement purchases are down from forecast and there is an offsetting increase to market volumes and consequent costs, it would appear that the customer will see the increased market costs through the proposed Heritage Deferral Account but the customer will not see an offsetting reduction in Energy Purchase Agreement costs. Please comment.

4.7 Please provide a list of anticipated terms and conditions for future Energy Purchase Agreements and include comment on whether the costs of these purchases will escalate at inflation or index or through some other means.

4.8 Page 4-10, Table 4-4: For each hydro project in the table, what is the storage associated with each facility in ksfd (thousand second foot days) and equivalent GWh? What "firmness" is attached to each energy contract, and how is each facility dispatched?

4.9 Page 4-10, Table 4-4: Explain the decrease in energy from ICP in F2005.

4.10 Page 4-10, Table 4-4 and Page 4-15, Table 4-5: Please provide the energy capability of the hydro resources outlined in these Tables under critical, average and maximum hydro conditions.

4.11 Page 4-17, Line 12: Note 1 reference appears to be incorrect, please state the correct reference.

4.12 Page 4-18, Table 4-7: Reviewing Net receipts of Non-Treaty Storage as indicated in Volume I, Tab 2, Schedule A-9, it appears that deliveries to the U.S. made in F2004 are replaced by receipts forecast in F2005 and F2006. Please provide an accounting of the Non-Treaty Storage Account for the years F2004-F2006 including any carry-forward from F2003. Please indicate the probabilities that receipts of Non-Treaty Storage will not occur and the reasons for a non-delivery. If there is a non-delivery, how will the loss of these receipts be made up and at what cost?

4.13 Page 4-18, Table 4-7: What are the obligations to provide storage under the Non-Treaty Storage agreement and do these obligations reduce the total storage available to BC Hydro? Please provide BC Hydro's obligations to take and return Non-Treaty Storage at BPA's request. Is there a charge to BPA for the use of Non-Treaty Storage and, if so, what is it? Is BPA the only other participant in Non-Treaty Storage? What are the benefits and costs of the Non-Treaty Storage agreement? Please provide a copy of the Non-Treaty Storage Agreement.

4.14 Page 4-18, Table 4-7: Is there an asymmetric "wear and tear" effect on generation resulting from storage more frequent transactions; i.e., is there an increased maintenance requirement from cycling the generation that would not occur if there were no storage transactions? If there is a significant impact, please quantify.

4.15 Page 4-21, Line 23: Provide examples of the accruals driving the load forecast.

Page 4-22, Lines16-17: What is the sensitivity of the load to +/- 5 Celsius degrees shift from expected? What is sensitivity to -10 Celsius degrees shift from expected? Is the load forecast weather, also the expected and "normal" weather? If it is an average, over what time period and how is it calculated?

4.16 Page 4-23, Table 4-10: With 3300 GWh required from Energy Calls, the 10 percent green criteria and the F2000 Green Energy Call, what drove the F2002 call to also require green characteristics? What incremental costs, if any, were incurred to attract the green criteria versus non-green resource that could have been realized? What is the maximum cost increment that is justifiable for green resource over non-green resource, and how is the value of the cost increment calculated?

Page 4-23. Please explain how the IEP target of 10 percent of new load growth met with Green resources reconciles with the energy plan target of 50 percent of new supply to be clean sources (page 1-5).

4.17 Page 4-27, Table 4-11: Is the energy capability for the Hydro Not Simulated in Schedule 5-2 on page 5-53, included in the Heritage Hydro energy capability for the years F2006 through F2013 in Table 4-11?

4.18 Page 4-27, Table 4-11: Please reconcile the planning criteria outlined on Page 4-19 in the event of low streamflow conditions when hydro generation gets down to 42,700 GWh, as indicated on page 5-20.

4.19 Page 4-27, Table 4-11 and Page 5-2, Table 5-1: Please explain the difference of 184 GWh for Heritage energy supply for F2006.

4.20 Page 4-28, Table 4-12: Please reconcile the Heritage capacity of 10,252 MW provided in Table 4-12 with Tables 5-18 to 5-20. Is there no capacity credit for Burrard and if not, why not?

5.0 Reference: Application, Volume I, Chapter 5, Heritage Contract

5.1 Page 5-1, Lines 8-12: Reconcile the costs referenced here against those shown in Schedule D1-1, page 2-79.

5.2 Page 5-2, Table 5-1 and Lines 17-18: Explain the sources for the reduction in "Forecast Supply of Energy under the Heritage Contract" in F2006 from F2005.

5.3 Page 5-2, Table 5-1: Please extend this table by year back to F1994.

5.4 Page 5-2. Please provide the heat rate for various levels of operation at Burrard. Please provide the fixed, variable O&M, and variable fuel costs for Burrard for F2005.

5.5 Page 5-2. Has BC Hydro recently requested from Powerex any long term firm gas contracts for service to Burrard and if so, please provide the length of those contracts and if they are conditional on the results of the MLA review?

5.6 Page 5-3, Table 5-2: Explain the differences and allocations of water rental costs against those shown in Schedule A-9, page 2-49 and Table 5-3, page 5-4.

5.7 Page 5-3, Table 5-2: Reconcile the gas purchase costs and gas transportation and domestic transmission costs with those shown in Schedule A-9, page 2-49 and those in Table 4-1.

5.8 Page 5-3, Table 5-2: Provide details regarding the Compensation and Mitigation Programs.

5.9 Page 5-4, Lines 6-7: How do the forecast market prices correlate to those shown in the long-run costing model? What model is used for the forecast in lines 6 and 7?

5.10 Page 5-6, Table 5-5: Classify labour expenses per Schedule D1-1 (page 2-79), and extend Table 5-5 back to F2001.

5.11 Page 5-7, Lines 17-19: What was the basis for the decision to choose F2014 as the end year for amortization of Burrard, and what are the current plans for Burrard beyond F2014 and for the longer term?

5.12 Page 5-8, Lines 16-18: Provide benchmarking studies reviewing BC Hydro's Generation reinvestment program.

5.13 Page 5-10, Table 5-7: Capital Plan by Category

Table 5-7 shows capital expenditures on "Facilities" for F2005 and F2006 in the amounts of $56.5 million and $79.8 million respectively.

For each annual expenditure shown, please identify the projects involved and the specific nature and individual costs of the work undertaken.

5.14 Page 5-10, Table 5-7: Extend Table 5-7 back to F1994 and out to F2008.

5.15 Page 5-10, Table 5-8: Is the $20 million revenue from the Skagit River Treaty net of transmission costs? Provide detail into the build-up of the $15.6 million transmission cost, in Table 5-2, page 5-3.

5.16 Page 5-10, Lines 16-18: Explain the nature of funds being received in excess of deliveries.

5.17 Pages 5-15, 5-16 and 5-17: Provide details of the Commercial Performance Calculation. Has BC Hydro performed any cost/benefit analysis with regard to the optimum level of commercial performance? If so what were BC Hydro's conclusions?

5.18 Page 5-17, Table 5-11: Extend Table 5-11 back to F1994.

5.19 Pages 5-17 and 5-18. Do Water Use Plan violations affect environmental performance? How is conformance to Water Use Plan specified operation monitored, reported and audited?

5.20 Page 5-18, Table 5-12: What drove the reduction in Environmental Regulatory Performance Target from F2003 to F2004?

5.21 Page 5-19, Figure 5-4: Provide annual WCB frequency and severity statistics for the period shown in this figure.

5.22 Page 5-20, Lines 13-14: Assuming full reservoirs to start each year, please provide the energy capability from the hydroelectric Heritage Resources given a repeat of the historical streamflow record for the years 1940 through F2000. What is the "critical" period and what is the energy capability for that period and does reservoir storage get to essentially empty at the end of that period?

5.23 Page 5-20, Table 5-14: Extend Table 5-14 back to F2001.

5.24 Page 5-21, Lines 14-16: Explain the differences, if they exist between a "normal" water inflow year and the seasonal water supply forecasts underpinning the medium and long term operating strategies.

5.25 Page 5-22, Lines 29-30: Please provide a copy of the Marginal Cost Model review. Please provide a list of the inputs to the Marginal Cost Model and the resulting outputs. What inputs require operational judgment and what operational judgments have been made?

5.26 Page 5-23, Line 5: Explain what "other studies" are used.

5.27 Page 5-25, Table 5-15: Extend Table 5-15 back to F2001, and explain the cause for the reduction from F2004 to F2005.

5.28 Page 5-26, Lines 12-14: Given the locational importance of and/or lack of storage at strategic facilities, and that "large" facilities would not have to spill for forced outages because of their storage capabilities, provide comment on the difference between the forced outage targets for strategic versus large facilities as shown in Table 5-11.

5.29 Pages 5-26 and 5-27. What software system is being used to manage the Reliability Centered

Maintenance program?

5.30 Page 5-27: Provide a comprehensive explanation of the application of the Equipment Health Rating process to transformers and generators and provide examples of the output and how it has been used.

5.31 Page 5-28, Lines 19-20: Provide a figure showing the Operating Factor against the CEA average since F1994 for each plant in Schedule 5-2.

5.32 Page 5-29. Provide a figure showing Forced Outages and Availability Factor since F1994 for each plant in Schedule 5-2.

Page 5-29. What criteria has BC Hydro developed with respect to equipment replacement for performance reasons. For example does BC Hydro develop "bathtub curves" for specific pieces of equipment and compare these to a standard requirement? Note: Although this question references generation equipment please consider it a general question for all of BC Hydro generation, transmission and distribution equipment.

5.33 Page 5-30, Figure 5-6: Why did preventive maintenance dip from F1997 to F2000, and what effect did this reduced maintenance have on the forced outage trend? No specific increase in forced outages is observed.

5.34 Pages 5-30, 5-31 and 5-32. Provide the most recent Haddon-Jackson detailed assessments and benchmarking reports.

5.35 Page 5-32, Lines 4-5: Has the Operating Factor been benchmarked to other utilities, and then correlated against costs? Are the starts and stops for each unit tracked and compared to reliability? If so, please provide data.

5.36 Page 5-32, Lines 14-15: How will decentralization help to manage costs? What functions would lend themselves to efficient decentralization?

5.37 Page 5-33, Tables 5-16 and 5-17: Provide Tables 5-16 and 5-17 back to F2001.

5.38 Page 5-36, Table 5-20: Given the historical streamflow period of October, 1940-September, 2000, what determines that this is the appropriate period of record for study purposes? What is the average hydro generation for this period? What is the average hydro generation for other periods that might be argued; i.e., the last 20 years, the last 30 years, the last 40 years. Has BC Hydro done any analysis to determine if there is any noticeable change in trend to annual runoff over the past 20-30 years? It appears that the load forecast is using a 30 year period to determine average temperatures, Volume II, Tab F, page 42. Is there a reason why the historical periods for streamflow and temperature are fundamentally different?

5.39 Page 5-37, Table 5-21: Provide Table 5-21 back to F2001.

5.40 Pages 5-38 to 5-40, Tables 5-22, 5-23 and 5-24: Provide the economic justification for all growth and Resource Smart capital projects proposed in Tables 5-22, 5-23 and 5-24 that underpinned the decisions to proceed with these projects.

5.41 Page 5-38, Table 5-22: Provide detail on GM Shrum transformer replacement. Is any portion of the cost of this project capable of being allocated to the Resource Smart program?

5.42 Page 5-38, Table 5-22: Provide Table 5-22 back to F2001.

5.43 Page 5-39, Table 5-23: Provide Table 5-23 back to F2001.

5.44 Page 5-40, Table 5-24: Provide Table 5-24 back to F2001.

5.45 Page 5-40. Please quantify the potential impact of the MLA Review on the operation of Burrard as it might impact customer rates and revenue requirement in F2005 and F2006; i.e., complete shutdown of Burrard, restricted to peaking only, available for energy only during periods of low streamflow, no restrictions on operation.

5.46 Page 5-41, Tables 5-25 and 5-26: Provide Tables 5-25 and 5-26 back to F2001.

5.47 Page 5-43, Line 19: Provide complete DamSmart database printout for Seven Mile and Jordan River facilities.

5.48 Page 5-45, Tables 5-27: Provide Tables 5-27 back to F2001.

5.49 Page 5-45, Table 5-27: Where do the operating costs for the people shown in the "Water Use Planning Project" (WUP) reside?

5.50 Page 5-45, Table 5-28: Why do WUP costs drop to $0.3 million in F2006? Are all WUPs complete, or is there an obligation for ongoing review and consultation?

5.51 Page 5-46. Please provide a copy of BC Hydro's policies on environmental and social performance.

5.52 Page 5-49, Table 5-29: Provide Table 5-29 back to F2001.

5.53 Pages 5-13 and 5-50. Please describe BC Hydro's current process to develop comprehensive water use plans for its heritage resources. Please comment on issues and risks for BC Hydro and quantify those risks in terms of possible loss of generation or additional costs where possible.

5.54 Page 5-49, 5-50, Section 9.5.2: Please explain the Water Rental Interim Order Remissions F2005. What change to operations drove the increase in costs and the resulting Remissions? Did the $3.5 million Remission cover all costs? Please explain why there were no Water Rental Interim Order Remissions for F2006? When does BC Hydro anticipate that Water Use Plans will be complete? Can BC Hydro quantify to any degree the anticipated increase in costs for each of the next five years resulting from additional implemented Water Use Plans?

5.55 Page 5-50, Lines 8 through 17: Given that the Water Comptroller has to date provided offsetting remissions against water rentals to BC Hydro for interim orders where there is a net loss in the value of energy, what mechanisms exist to insulate customers from revisions to water licences that would reduce the amount or value of deliverable Heritage Electricity?

5.56 Page 5-51, Table 5-30: Provide Table 5-30 back to F2001.

5.57 Page 11-15, Section 2.2.7: The completion of Water Use Plan project appears to be in F2006. Explain what, if any, ongoing costs are forecast in F2005, F2006, and beyond F2006 for maintenance and execution of the plans, and identify where those costs will reside.

5.58 Page 5-53, Schedule 5-2: Regarding Note 2, is the load forecast also based on a 60 year weather record?

5.59 Page 5-53, Schedule 5-2: Please explain why the 321 GWh indicated on Schedule 5-2 for Hydro Not Simulated appears to differ from the sum of the energy capabilities for those plants in Tables 5-18 through 5-20 of 266 GWh.

5.60 Page 5-54, Schedule 5-3: Provide the complete plans and reports (Facility Asset plans, RCM, HER and EMS) for the GM Shrum and Seven Mile facilities.

6.0 Reference: Application, Volume I, Chapter 6, Transmission

6.1 Page 6-23, Lines 19-20: The Application states that "Contingency plans are prepared to mitigate the system consequences of unanticipated asset failures."

It is expected that these plans would be prepared well in advance of need to address several likely contingency situations.

Please provide the following:

(a) A description of the contingency plans that have been prepared over the last ten years to mitigate the impact of major transmission asset failures.

(b) A description of the approximate costs and benefits of those contingency plans that have had to be implemented over the last ten years.

6.2 Page 6-2, Section 3.2.8.1, Asset Condition/Health

The Application mentions that a qualitative asset condition evaluation system is used for transmission lines, stations and vegetation.

Please elaborate on the details of this evaluation system and explain how the success of its application is measured. Was information which emanated from this evaluation used in the preparation of the graph (Figure 6-1) on page 6-26? If yes, please explain how it was used. If no, please explain how the information for the graph was obtained.

6.3 Page 6-4, Lines 16-17: Please describe and quantify the additional costs for BCTC which were not part of BC Hydro's previous transmission costs.

6.4 Pages 6-5 and 6-48, Lines 14 and 15: BCTC states that higher system use is acting to reduce transmission rates. Please describe how this use is occurring and how will BCTC forecast future use. Does this increasing use also have additional costs (i.e. additional maintenance or sustaining capital costs)? If possible, please quantify.

6.5 Page 6-7, Table 6-1: Please describe BCTC'S asset retirement obligation.

6.6 Page 6-11, Lines 21, 22: BCTC states that the operations and control infrastructure is showing signs of strain limiting effective and reliable operation. Please describe the signs and discuss whether these limitations and problems pose any risk for the reliable transmission of power within B.C.

6.7 Page 6-20, Table 6-6: Vegetation Management. Please provide the last five years of expenditures for all transmission related vegetation management programs. Please describe all new (post F2000) environmental regulations or First Nations requirements which have increased the cost of vegetation management and quantify where possible.

6.8 Page 6-24. Please describe the quality assurance program that BCTC will implement to determine if the condition assessment audits are being performed adequately. Please also describe any other quality assurance programs.

6.9 Page 6-28. Supply to Vancouver Island. BCTC states that several initiatives are underway to improve the reliability of supply to Vancouver Island. Please describe these initiatives.

Page 6-51, Table 6-18, 500 kV Cable Shore Cooling System upgrades. Please describe the nature of this project. Will this or any other initiatives increase the firm transfer capability to Vancouver Island? If so, by how much?

6.10 Page 6-28, Section 3.2.8.2.2, Lines 12-26

The Application states that the final report of the WECC Compliance audit showed that BC Hydro Transmission system did not measure up to all the planning standards and operating standards that have been incorporated in the WECC Reliability Management System. The Application also states that a mitigation plan has been prepared to resolve the operating measure and planning measure.

Please file a copy of this mitigation plan, including a copy of the "fully developed plan for mitigating capacity shortages".

6.11 Page 6-28, Section 3.2.8.2.2, Lines 27-30

The Application mentions that the WECC conducts periodic operating audits of compliance to operating policies and standards. Also mentioned is the most recent WECC audit of BC Hydro's transmission system, conducted in August 2001.

Please provide a copy of the final report on the August 2001 WECC operating audit of the BC Hydro's transmission system. Also provide a description of the implementation details for the five follow-up recommendations in the report.

Page 6-28. WECC compliance. Is WECC contemplating a number of maintenance standards for inclusion in its mandatory compliance programs? If so, please describe these initiatives and the consequence for BCTC.

6.12 Page 6-38, Lines 7-9: Please describe the security rating standards for major transmission lines. Do these standards resemble the original design standards for these lines? Did the original design standards require that line clearing be such that no danger trees should encroach the transmission lines? If so, why have the original standards not been maintained?

6.13 Page 6-39, Lines 11 and 12: When did the new Pest Management Act come into effect? Will this cause any cost increases for BCTC or BC Hydro? If so, please estimate the impacts. How did BC Hydro manage its herbicide programs before the new Act?

6.14 Page 6-41. BCTC states that an additional 36 positions are required for asset management and corporate functions. Please describe the need for these additions.

6.17 Page 6-47, Lines 21-23: BCTC describes sustaining capital as capital expenditures which extend the life of an asset by 20 percent or more. Is this definition used universally in BCH? When did this definition come into effect? If the definition changed, please quantify the amount of sustaining capital which would have previously been classified as maintenance expenses under the old definition since F1994?

6.15 Page 6-49, Table 6-16: Sustaining capital plan. Please provide an example of the reports used to justify particular projects in these plans, e.g., Power Transformers or Protection and control projects.

6.16 Page 6-50, Table 6-17: Are capital expenditures for IPP's offset by the contributions in aid of construction? If so, please explain the difference in the 2006 plan. If not, how are these contributions accounted for and how much are they?

6.17 Page 6-50, Load Growth, Lines 12-14

The Application mentions that the capital costs include several significant projects required to meet BC Hydro's demand for Network Integration Transmission Service.

The first project mentioned involves an increase in the transfer capability from the Interior to the Lower Mainland.

Please provide details of the actual project or projects contemplated to accomplish this, and the associated costs.

6.18 Page 6-50, Load Growth, Line 15

The Load Growth capital program in the Application includes a project to "replace the reactive capability of the Burrard Generating Station."

Please reconcile this project with the information contained on page 5-40 which indicates that in the near term, Burrard units 1, 2 and 3 will be utilized to provide VAR support for voltage support requirements on the BC Hydro transmission system.

6.19 Page 6 -50, Load Growth, Lines 20-23

The Application states that several substation upgrades are contained in the growth capital plan, as well as a new substation construction. Amounts of $8.4 million and $78.0 million have been allocated for F2005 and F2006 respectively.

Please provide details of the specific projects that will incur these costs. Your response should include cost allocations for each individual project over the two test years.

6.20 Page 6-55, Line 16: Does BCTC budget for distribution capital projects? If so, how are these projects charged to BC Hydro?

6.21 Page 6-74. Congestion management costs. Please describe the nature of these costs.

7.0 Reference: Application, Volume 1, Chapter 8, Power Smart, Customer Care and Energy Management

7.1 Page 8-18. Does BC Hydro anticipate any significant impacts to customer rates if the proposals for Stepped Rates are implemented? If so, please provide an estimate of those potential impacts and please indicate to what degree potential impacts have been incorporated into the Rate Application for F2005 and F2006.

8.0 Reference: Application, Volume I, Chapter 11, Capital Expenditures

8.1 Page 11-1, Table 11-1: Explain the reason and source of the differences for the "Retirements" line items in Capital Assets in Service and Accumulated Depreciation.

8.2 Page 11-2, Table 11-2: Provide Table 11-2 back to F2002.

8.3 Page 11-2, Table 11-2: Explain the difference shown for Generation related capital in this Table versus the Generation capital shown in Table 5-7 on page 5-10, and show where any differences are allocated.

8.4 Page 11-2, Table 11-2: Explain the decreasing nature of the line item "Surveys & Investigations (including Aboriginal Negotiations)" contrasted against earlier statements in the summary that forecast increasing costs due to effects from Environmental programs and First Nations issues.

8.5 Page 11-2, Table 11-2: Provide the sources and explain the details of the line items "CIA - specific" and "CIA - Recurring".

8.6 Page 11-2, Table 11-2: Provide details of the "Computers" line item.

8.7 Page 11-3 and 11-4, Table 11-3: Provide details surrounding the capitalization of Dam Deficiency Investigations instead of holding these costs in investigative accounts.

8.8 Page 11-7, Section 2.1.6: Provide greater details of the programs and tools that were implemented as part of this project, and the improvements made to modeling tools utilized to manage BC Hydro's reservoirs.

8.9 Page 11-8, Lines 2 and 3: Provide the economic analysis that supported the decision to rehabilitate Burrard Unit 1. Please also explain the nature of the additional estimated cost of $14.7 million for the generating station upgrade (per Table 11-3) beyond the $184.6 million spent up to March 31, 2003.

8.10 Page 11-8, Lines 20 to 23: What specific improvements were made to the units used for VAR support, and what criteria were used to economically justify the specific improvements in light of their dispatch solely for VAR support?

8.11 Page 11-13, Line 18 to 23: Please provide the economic analysis for the replacement of exciters on GM Shrum units 1-8.

8.12 Page 11-13, Line 18 to 23: Provide the economic evaluation supporting the replacement of the generator transforms and the comparison to the option of rewinding the transformers.

8.13 Page 11-19, Section 2.2.18: Has the manufacturer of the original Mica generators offered any economic assistance towards the resolution of the problem? Are there any remedies available similar to those being pursued as described in Section 2.2.19? If not, why not?

9.0 Reference: Application, Volume II, Appendix J

9.1 Page 4, Table 6: Is the Net Storage Returns (Exchange Nets) otherwise called Non-Treaty Storage and are Net Storage Returns (Exchange Nets) the same as Plus Exchange (net) indicated in Volume I, Tab 4, Table 4-7. If it is Non-Treaty Storage, can receipt and return obligations drive surplus sales and additional Powerex purchases?

9.2 Page 4, Table 6: Given that Hydro generation was significantly up in F2003, was it Net Storage Returns that drove Net Purchase from Powerex as indicated for F2003 in Table 6?

9.3 Page 4, Table 6: Please explain Other Energy Purchases and Net Purchase from Powerex in Table 6 and the difference between the two. Was there an agreement similar to the present Transfer Pricing Agreement in place during F2003 with the "exclusivity" clause? Please explain the difference in pricing between the two purchases indicated in Table 8.

9.4 Page 5. Please rationalize Lines 13-16 against the annual average market purchase rates set out in Volume I, Tab 2, Schedule A-9, Line 43 which seem to indicate a significant downward trend.

9.5 Page 5, Table 7: As indicated in Table 7, what is the Bypass Transportation Agreement between Terasen and BC Hydro and does this agreement extend, and impact customer rates, beyond F2003?

9.6 Page 5, Table 8: Please provide the average cost of natural gas used at Burrard Thermal from F1994 through F2003. Please provide the monthly forecast of gas prices to BC Hydro for Burrard Thermal for F2005 and F2006 used to establish Volume I, Tab 5, Table 5-2 and indicate from where this forecast originates.

9.7 Page 5. Given the statement on the market on page 5, Lines 13-16, does BC Hydro anticipate sales to Powerex out of thermal when market prices exceed the variable thermal costs? What constraints are there to running Burrard for export at times when it is surplus to the load requirements of the Integrated System and when the variable cost is less than the Threshold Sale Price?

9.8 Page 19. Please provide the status of RTO West and please elaborate on the statement on page 19, Lines 1-2 that " …efforts in this regard will protect and enhance that electricity trade value." Are negotiations still proceeding and if so when are they anticipated to be concluded? What are the major issues and/or stumbling blocks? The Commission directed Aquila to enter into discussions with BC Hydro regarding an Independent System Operator for B.C. What is the status of those discussions?

10.0 Reference: Application, Volume II, Appendix K

Pages 5 and 9, Definition 1.1.17: Please provide a list of these Interutility Agreements. Clause 5.2. Please explain the qualifier leading off the first sentence, "Except as provided by Interutility Agreements." The definition of Interutility Agreements seems to preclude purchases. What are the terms of those agreements that might drive sales or purchases?

11.0 Reference: Application, Volume 1, Chapter 6, p. 6-36

Preamble: Page 6-36 of the Application states that Transmission has 75,000 wooden pole structures. It would seem reasonable to expect that wooden poles would have a longer life in dry Interior locations than in wet coastal areas like the Lower Mainland and Vancouver Island.

11.1 Please define Wet (e.g., the Lower Mainland and Vancouver Island) and Dry (e.g., the remainder of the Province) locations that together cover the total number of Transmission poles in service, and state how many wooden poles Transmission currently has in service in each of Wet and Dry locations.

11.2 How many wooden poles does Transmission plan to replace in each of F2005 and F2006 in each of Wet and Dry locations? What is the forecast average and total cost of such pole replacements in each of Wet and Dry locations?

11.3 Please explain how BC Hydro estimated the number of wooden Transmission poles that it plans to replace in F2005 and F2006.

11.4 What is the age distribution of the wooden poles currently in Transmission service in each of Wet and Dry locations, and the average age of such poles that are expected to be replaced in F2005 and F2006?

11.5 For each of Wet and Dry locations, please explain the basis on which BC Hydro and BCTC decide when a wooden Transmission pole needs to be replaced, including on-site evaluation of the pole, and the age and other criteria.

11.6 For each of the Wet and Dry locations, what was the average age and the age distribution of wooden Transmission poles that BC Hydro replaced in each of the past five years?

11.7 For each of the past five years, and for each of Wet and Dry locations, what was the average cost per pole and total cost of replacing wooden poles in the Transmission System?

11.8 For each of the past five years and each of Wet and Dry locations, what was the budget for wooden Transmission pole replacement and the variance between budget and actual? Please explain the reasons for any significant variances.

12.0 Reference: Application, Volume 1, Chapter 7, Section 2.7, pp. 7-23 and 7-24

Preamble: Pages 7-23 and 7-24 of the Application states that Distribution has 876,000 poles and that the average life expectancy of poles is 40 years. It would seem reasonable to expect that poles would have a longer life in dry Interior locations than in wet coastal areas like the Lower Mainland and Vancouver Island.

12.1 Please define Wet (e.g., the Lower Mainland and Vancouver Island) and Dry (e.g., the remainder of the Province) locations that together cover the total number of Distribution poles in service, and state how many wooden poles Distribution currently has in service in each of Wet and Dry locations.

12.2 How many poles does Distribution plan to replace in each of F2005 and F2006 in each of Wet and Dry locations? What is the forecast average and total cost of pole replacements in each of Wet and Dry locations?

12.3 Please explain how BC Hydro estimated the number of Distribution poles that it plans to replace in F2005 and F2006. Is there a direct link to the statement on page 7-24 that 15 percent of the poles are older than the average life expectancy?

12.4 Further to Figure 7-3 on page 7-24, what is the age distribution of the poles currently in service in each of Wet and Dry locations, and the average age of poles that BC Hydro Distribution expects to replace?

12.5 For each of Wet and Dry locations, please explain the basis on which BC Hydro decides when a Distribution system pole needs to be replaced, including on-site evaluation of the pole and the age and other criteria.

12.6 For each of the Wet and Dry locations, what was the average age and the age distribution of Distribution poles that BC Hydro replaced in each of the past five years?

12.7 For each of the past ten years, and for each of Wet and Dry locations, what was the average cost per pole and total cost of replacing poles in the Distribution System?

12.8 For each of the past five years and each of Wet and Dry locations, what was the budget for Distribution pole replacement and the variance between budget and actual? Please explain the reasons for any significant variances.

13.0 Reference: Application, Volume 1, Chapter 4, Table 4-4, p. 4-10

13.1 Please expand Table 4-4 on page 4-10 to identify for each IPP where the cost of energy purchases from the IPP is related to some market factor such as cost of fuel gas or market electricity prices and the pricing basis for such variable pricing.

13.2 Where a dispatchable IPP is projected to deliver materially less than its maximum available energy, please explain.

13.3 Please explain the basis for the forecast that Alcan will deliver 1,230 GWh/year in F2005 and F2006?

14.0 Reference: Application, Volume 1, Chapter 4, Table 4-3, p. 4-19

14.1 Page 4-19 states that BC Hydro is exposed to gas market prices for ICP, Fort Nelson, Burrard Thermal and Prince Rupert. Does the price of power purchased from the McMahon Co-generation Project reflect gas or electricity market prices? If yes, please explain the arrangement.

14.2 For which thermal plants is the cost of fuel gas supplied by BC Hydro (or paid for by BC Hydro) included in the energy purchase costs shown in Table 4-3 on page 4-9? What are the quantities and costs of this fuel gas in F2005 and F2006?

14.3 The cost of fuel gas purchases for Burrard and Fort Nelson are shown in Table 5-2 on page 5-3. Aside from Tables 4-3 and 5-2, are fuel gas costs for any other thermal plants included in the Application? If the answer is yes, what are the plants, where are the fuel costs shown, and what are the quantity and cost of such fuel in F2005 and F2006?

14.4 What is the heat rate for each thermal plant where BC Hydro is exposed to gas market prices?

14.5 By month for F2005 and F2006, what is the total quantity and cost of fuel gas that BC Hydro forecasts it will provide or otherwise bear the cost of?

14.6 By month for F2005 and F2006, how much of the foregoing fuel gas quantity and cost is currently fixed by fixed price purchase arrangements, financial hedges or otherwise?

14.7 For the portion of fuel gas requirements that currently does not have fixed prices, please provide a schedule of the monthly purchase volume, the purchase location(s) and forecast gas price(s). What is the basis of the gas price forecast, and when was it prepared?

14.8 Addendum 1 of BC Hydro's Vancouver Island Call for Tenders identifies four gas price forecasts that will be used to evaluate bids. Please provide a schedule by month that estimates the cost of BC Hydro fuel gas requirements for F2005 and F2006 using each of the four CFT price forecasts for the quantity of gas that currently does not have a fixed price.

14.9 Please explain how BC Hydro allocates fuel gas costs between the several thermal generating stations. If fuel gas cost is not allocated on an average cost of gas basis, please provide the fuel quantity, fixed price gas cost and forecast variable gas cost for each thermal generator in F2005 and F2006.

15.0 Reference: Application, Volume 1, Chapter 4, p. 4-16

15.1 BC Hydro states that gas transportation costs and non-BCTC transmission costs are forecast at $13.0 million in each of F2005 and F2006. For each significant service arrangement, please identify the party that provides the service, briefly outline the service provided and state the annual cost. Please confirm that the costs on page 4-16 do not include the Burrard gas transportation and Skagit transmission costs shown in Table 5-2 on page 5-3.

15.2 For each service arrangement, please identify the extent to which the forecast cost represents a firm commitment on the part of BC Hydro, an arrangement that BC Hydro may terminate, or service which it expects to commit to at a future date.

15.3 To the extent that Powerex holds gas transportation and non-BCTC transmission service that in addition to that discussed in the two preceding questions and for each significant service arrangement, please identify the party that provides the service, briefly outline the service provided and state the annual cost.

16.0 Reference: Application, Volume 1, Chapter 4, p. 4-18
Application Letter dated December 15, 2003

16.1 In its December 15, 2003 letter, BC Hydro states that its F2005 budget will be approved in January 2004 and data related to snow pack and reservoir levels that affect the F2005 forecast will be much firmer in February 2004. Please refile Table 4-7 on page 4-18 based on the most current information at the time the Information Request is responded to.

16.2 If more current information results in a material change to the Heritage payment obligations including market purchases, please discuss the changes and identify the recalculated Heritage payment obligation.

16.3 Fort Nelson generation is shown as 156 GWh/year for F2005 and F2006. What was the generation at Fort Nelson in F2002, F2003 and F2004?

16.4 Please explain how power generated at Fort Nelson that is in excess of local load is disposed of, the gross and net revenue from any sales of excess power from Fort Nelson in F2002, F2003 and F2004, and how any net revenue generated by such power sales are accounted for by BC Hydro and Powerex.

16.5 What sales of power generated at Fort Nelson that is in excess of local load is forecast for F2005 and F2006, and what are the forecast net revenues from these sales? Where are such sales and revenue reported in the Application?

16.6 Please explain why the foregoing forecast fully represents the potential for net revenue from sales of excess power at Fort Nelson.

16.7 Please confirm that the gas purchase costs for Burrard and Fort Nelson shown in Table 5-2 on page 5-3 correspond to the generation from these plants shown in Table 4-7 on page 4-18, or explain any differences.

17.0 Reference: Application, Volume 1, Chapter 5, Tables 5-16 and 5-17, p. 5-33

17.1 Table 5-17 on page 5-33 reports (new) Resource Smart Energy Gains of 104 GWh in F2005 and 31 GWh in F2006. What Resource Smart gains were made in F2003 and F2004?

17.2 Please explain whether the Resource Smart capital expenditures shown in Table 5-16 on page 5-33 are added to Capital Assets in Service annually as they occur, or when the project goes into service. For example, do Resource Smart expenditures in F2005 affect F2006 revenue requirements? Please explain the reasons for the accounting treatment.

17.3 Table 4-11 on page 4-27 shows 208 GWh from Committed New Resource Smart and 58 GWh from Planned New Resource Smart in F2007, but nothing for earlier years. Please explain where the Resource Smart energy gains for F2005 and F2006 that are reported in Table 5-17 are reflected in Table 4-11.

18.0 Reference: Application, Volume 1, Chapter 11, Table 11-1, p. 11-2

18.1 Table 11-1 on page 11-2 states that Capital Assets in Service at the beginning of F1994 were $11.726 million. What was the latest (most recent) year-end actual Capital Assets in Service that was available at the time of BC Hydro's February 11, 1994 Revenue Requirements application?

To what extent was that Capital Assets in Service number used as a basis for the 1994 application?

18.2 If the foregoing latest actual Capital Assets in Service that was available at the time of the 1994 application was not the number of $11.726 million at the beginning of F1994, please explain and reconcile any differences.

18.3 Please provide a schedule showing the yearly additions and retirements for Capital Assets in Service from the forgoing latest actual Capital Assets in Service number that was available at the time of the 1994 application to the actual year-end F2003, in the form of Table 11-2 on page 11-2 and identifying both sustaining and growth expenditures for each year.

19.0 Reference: Application, Volume 1, Chapter 5, Section 9, p. 5-45

19.1 Please expand Table 5-28 on page 5-45 by year back to the beginning of F1994, identifying both sustaining and growth capital for each year. The expanded table should also show the total for each year of capital expenditures below $2 million for each of First Nations Negotiations and Water Use Programs.

19.2 Please explain the nature of the expenditures for First Nations Negotiations that are shown in Table 5-28 on page 5-45.

19.3 For each category of capital expenditures on First Nations Negotiations, please clarify if the expenditure is in response to a legislative or regulatory requirement, a Provincial government policy or a BC Hydro policy. Where expenditures are in response to BC Hydro policies, please explain why the expenditures are required.

19.4 For each category of capital expenditure on First Nations Negotiations, please explain why the amount should be capitalized rather than expensed during the year incurred. Please confirm that capitalizing these expenditures is consistent with standard accounting practices and BC Hydro policy.

20.0 Reference: Application, Volume 1, Chapter 6, p. 6-8

20.1 The Application at page 6-8 states that, as the transmission owner, BC Hydro will be responsible for property services and First Nations relations related costs. Please describe the activities that each of these costs relates to, and identify any portions that will be capitalized.

20.2 What property services and First Nations relations related costs for transmission are forecast for F2005 and F2006, and what were the corresponding expenses in F2001 through F2004? Please confirm these costs are separate from those reported in Tables 5-27 and 5-28 on page 5-45.

20.3 In Table 6-9 on page 6-40 why are Property Services expected to increase from $0.4 million in F2005 to $1.0 million in F2006?

21.0 Reference: Application, Volume 1, Chapter 1, p. 1-15

21.1 The Application at page 1-15 identifies the principal cost drivers that are responsible for the revenue requirements increase from F1994 to F2005 and F2006. Please provide a schedule that shows for each identified cost driver and for BC Hydro’s total revenue requirement, the F1994 cost and the increase from F1994 to actual F2003 and to F2005 and F2006, in terms of dollars, percent increase, average percent increase per year, dollars per kWh and dollars per customer.

21.2 For costs related to management of environmental and First Nations issues, please provide a similar breakdown of the revenue requirements increase for each of environmental and First Nations in terms of generation, transmission and distribution costs.

22.0 Reference: Application, Volume 1, Chapter 7, Section 2.2, p. 7-4

22.1 Pages 7-4, 7-5 and 7-6 of the Application do not identify management of Environmental or First Nations issues as major factors influencing Distribution expenditures. If forecast Distribution expenditures in these areas in F2005 and F2006 are significant, please provide the forecast expenses and capital expenditures.

23.0 Reference: Application, Volume 1, Chapter 9, Section 5 (Powerex Corp.), pp. 9-46 to 9-50

23.1 Page 9-46 of the Application states that only purchase and sales transactions that support trading activities are identified in Trade Income. Please expand Table 9-19 on page 9-50 to include Trade Income for F1999 through F2003, and to show a detailed breakout of the significant categories of revenue and costs that yield the total Trade Income. For each category that involves electricity sales or purchases, please state the quantity of electricity that was transacted in the year.

23.2 Please separate the purchase and sales transactions (quantity and cost/revenue) in the expanded Table 9-19 as to transactions that involve electricity movements in and out of British Columbia, and electricity transactions that occur outside the Province. If the latter transactions are not the same as the Off-System transactions that are reported in BC Hydro's quarterly Export Trade Reports, please explain.

23.3 For F1999 through F2006, what are the total actual or forecast Off-System revenue and costs? In addition to electricity sales and purchases, please explain any other revenue or costs that are included.

23.4 Please explain the budgeting and review process that BC Hydro and Powerex use to forecast Trade Income. That is, what is the process for preparation of the annual forecasts of Trade Income and when are they prepared; what is the approval process at BC Hydro for the forecast; what is the nature of reporting on variances between actual and forecast and how are variance reports reviewed by and dealt with BC Hydro?

23.5 Further to the comment on page 9-47 that third party sales are expected to reach 42,000 GWh in F2006, please define "third party sales" in relation to the categories shown in expanded Table 9-19.

23.6 What is Powerex' current position with regard to fixed price electricity purchases for each of F2005 and F2006, in terms of quantity and dollar value? What is the current mark-to-market position for these transactions?

23.7 To what extent do the fixed price purchases and sales positions offset one another, from a risk management perspective?

23.8 Please repeat the foregoing three questions with respect to natural gas purchases and sales.

23.9 Please confirm that the foregoing fixed price energy positions are reflected in Table 9-19 on page

9-50. Please explain if Powerex incorporates forecast Trade Income in its risk management objectives and, if so, how is this objective stated?

23.10 Further to the discussion on page 9-49, what are the assumptions about energy prices, regional demand, level of economic activity in Canada and the U.S., and other factors that support the estimates of Trade Income for F2005 and F2006?

23.11 Further to the discussion on page 9-49, please explain why point-to-point ("PTP") transmission costs increased from F2003 to F2004, are expected to increase for F2005 and decrease for F2006. To what extent are rate changes responsible for the changes in the transmission costs? How much of the forecast PTP costs for F2005 and F2006 are service arrangements that Powerex has not yet committed to or can terminate?

23.12 Further to the discussion on pages 9-49 and 9-50, please outline the amounts that Powerex currently has recorded in its books regarding potential liabilities from past years' activities.

23.13 Further to the discussion on page 9-50, please outline the amounts from past trading activities that could result in additional income. When did these amounts arise, generally who owes them and what is Powerex doing to collect them?

LOAD FORECAST

24.0 Reference: Application, Vol. 1, Tab 4, p. 4-21
Total Gross Energy Requirements

The Application indicates that there are six major components to the BC Hydro's Load Forecasts. One of the six components is "accruals". Please explain what it is and its volume relative to the total requirements.

25.0 Reference: Application, Vol. I, Tab 4, p. 4-22; Vol. II, Tab F, Tables A7.1–7.6 & p. 42 Demand Uncertainty

The Application estimates of high and low load projections are based on varying assumptions of longer-term economic and other trends.

25.1 Please update the "53,929 GWh" in the Integrated System Total Gross Requirements for 2004/05 Low Scenario Load Forecast With Power Smart (Table A7.6) if this figure is found to be incorrect. If this figure is correct, please explain why the 2004/05 energy requirement is forecast to be lower than the 53,997 GWh forecasted for 2003/04.

25.2 Using the same Monte Carlo Analysis, please prepare another high and low scenario by varying the following two out of the five major causal factors with the following substitute new assumptions:

(i) Electricity Rates – The probable scenario assumes that electricity prices will increase at the rate of inflation. The low scenario assumes that electricity prices will increase at the rates applied for in this Application, and the high scenario assumes that prices will stay at the 2003 level;

(ii) Effective Energy Reduction of DSM Programs – The annual low, probable and high reductions from DSM used are 25 percent, 100 percent and 125 percent, respectively, of the expected reductions.

26.0 Reference: Application, Vol. I, Tab 4, p. 4-22
Short-term Uncertainty

The Application states that short term uncertainty driven by weather variations and economic conditions can cause load variations of 1 percent to 2 percent to both energy and capacity.

26.1 Please provide the variations from the annual Load Forecast 1997 to Load Forecast 2001 for the period F1999 to F2003. Please describe the extent of variations that can be explained respectively by weather variations and economic conditions.

26.2 In the recent past five years, how often did BC Hydro have to rely on short-term market purchases? Please provide details on timing and volume.

27.0 Reference: Application, Vol. II, Tab F, p. 33
Comparison Between Reference Energy Forecasts with Power Smart

Please issue a replacement page correcting for the error in the second sentence in Section 6.2 where it states that "the *2002* forecast is above the *2003* forecast by 227".

28.0 Reference: Application, Vol. II, Tab F, pp. 14, 43
Residential Forecast - Methodology

The Application summarizes that the residential forecast methodology is based on the number of residential accounts times the rate of use. The use rates are based on billed data as anchor information, combined with data from the REUS survey used as inputs to the REEPS model.

28.1 Please explain the data collection process in REUS by including a brief description on how the sample is updated each year. Please provide a copy of the survey.

28.2 Please describe how the end use analysis in the REEPS model evaluates the DSM programs to produce the Before Power Smart and With Power Smart load forecasts.

29.0 Reference: Application, Vol. II, Tab F, pp. 22, 43-45
Residential Sales

29.1 Please explain how the external forecasts made for calendar year (X-ref Tab F, Table 4.2) are adapted to fiscal year forecasts for analysis.

29.2 Please complete the following tables.

LOWER MAINLAND	F2003 ACTUAL		F2004	F2005	F2006
Population (million)					
Housing Starts (% change)					
Number of Residential Accounts					
Weighted Ave Use Rate (GWh)	(normalized)	(actual)			
Sales Before Power Smart (GWh)	8,201(normalized)	(actual)	8,348	8,508	8,680
Sales With Power Smart (Gwh)	(normalized)	(actual)			

VANCOUVER ISLAND	F2003 ACTUAL		F2004	F2005	F2006
Population (million)					
Housing Starts (% change)					
Number of Residential Accounts					
Weighted Ave Use Rate (GWh)					
Sales Before Power Smart (GWh)	4,049 (normalized)		4,104	4,165	4,230
Sales With Power Smart (Gwh)					

SOUTH INTERIOR	F2003 ACTUAL		F2004	F2005	F2006
Population (million)					
Housing Starts (% change)					
Number of Residential Accounts					
Average Use Rate (GWh)	1,749 (normalized)				
Sales Before Power Smart (GWh)			1,765	1,793	1,824
Sales With Power Smart (Gwh)					

NORTHERN REGION	F2003 ACTUAL		F2004	F2005	F2006
Population (million)					
Housing Starts (% change)					
Number of Residential Accounts					
Weighted Ave Use Rate (GWh)	1,465 (normalized)				
Sales Before Power Smart (GWh)			1,473	1,490	1,510
Sales With Power Smart (Gwh)					

BC HYDRO TOTAL	F2003 ACTUAL		F2004	F2005	F2006
Population (million)	3.82				
Housing Starts (% change)					
Number of Residential Accounts	1,442,597				
Weighted Ave Use Rate (GWh)	15,464(normalized)				
Sales Before Power Smart (GWh)			15,688	15,955	16,244
Sales With Power Smart (Gwh)					

30.0 Reference: Application, Vol. II, Tab F, pp. 14-15, 48-53

Commercial Forecasts - Methodology

The Application summarizes that the commercial forecast methodology for the building portion of the sector is based on floor stock times end use times the intensity for each end use.

30.1 Please explain how BC Hydro annually updates the floor stock by segment.

30.2 Page 15 indicates that the shares of end-use stock come from COMMEND model and are updated from CPR.

30.2.1 Please clarify where the original input data for "shares" come from.

30.2.2 Please describe how the descriptions of short and long-term population, demographic and economic forecasts on pages 48-53 are quantified as SHARE and STOCK input variables to the COMMEND model.

30.3 How are EUI values developed?

30.4 Please describe the expected change in EUI values used in the model for the years F2003 to F2006.

30.5 Please explain if the commercial load forecast with Power Smart is part of the COMMEND model output or whether it is analyzed external to the model.

30.6 Please describe the degrees of freedom and the statistical tests in the regression analysis by major sector (transportation, communications, utilities, others) for COMDNB.

30.7 Please comment on the various growth rates by sector in the non-building segment during F2004 to F2006 based on the regression analysis.

31.0 Reference: Application, Vol. II, Tab F, Table 9.2
Commercial Sales

31.1 Please complete the following table for the period 1998/99 to 2005/06.

	BUILDING SECTOR (COMDB)	NON-BUILDING SECTOR (COMDNB)	TRANSMISSION (COMT)	TOTAL (GWh)
1998/99 (Actual)				12,814
1999/00 (Actual)				13,176
2000/01 (Actual)				13,654
2001/02 (Actual)				13,583
2002/03 (Actual)				13,729
2003/04				13,908
2004/05				14,120
2005/06				14,403

31.2 Please repeat Table 8.1 based on sales forecast with Power Smart.

32.0 Reference: Application, Vol. II, Tab F, pp. 15-16, 56, 58, Table 10.3
Industrial Forecast Methodology and Sales

The Application indicates that industrial distribution energy forecast was based on a time series regression analysis whereas transmission voltage customers forecast for the short-term is done on a customer by customer basis.

32.1 Please describe if the provincial GDP independent variable in the industrial sales analysis is real or nominal.

32.2 Based on the time series analysis, please describe which industrial sector "j" is most affected by provincial GDP activity and which is least dependent on GDP activity.

32.3 Please repeat Table 10.3 for the period 1998/99 to 2005/06 by showing the effects of Power Smart.

33.0 Reference: Application, Volume I, Tab 2, pp. 2-2 to 2-4

33.1 Table 2-2 shows the detailed pro forma consolidated statement of operations with tariff rates unchanged and Table 2-3 shows the same statement with rates increased by the proposed rate increases of 7.23 percent and 2.0 percent.

Normally these types of schedules are used to determine the overall Utility Revenue Requirement percentage increase which is then used to calculate the average increase in customer rates.

When the total revenues in Table 2-2 are compared to Table 2-3 an increase of 6.68 percent for F2005 is calculated ($2,826/$2,649). Please explain why the rate increase for F2005 is expressed as 7.23 percent rather than 6.68 percent.

34.0 Reference: Application, Vol. II, Tab F, pp. 38-40
Sensitivity Analysis

34.1 The sensitivity analysis shows that the value of GDP elasticity is estimated at 0.42.

34.1.1 Please provide the same analysis at a disaggregated level for residential, commercial and industrial consumption before aggregating the results to produce BC Hydro Sales and the total gross requirements.

34.1.2 Please re-state the results in Table 7.1 for the period 2003/04 to 2005/06 based on the disaggregated approach in 10.1.1.

34.2 Please provide the 1993-2002 price index used in the analysis.

34.3 Please provide the econometric analysis on consumption changes to price changes at a disaggregated level (residential, commercial, and industrial) to produce BC Hydro Sales.

34.4 Please re-state the results in Table 7.2 for the period 2003/04 to 2005/06 based on the disaggregated approach in 10.3.

34.5 Please provide an explanation, qualitative or quantitative, of the differences between the econometric analysis results of price elasticity and the literature on price elasticity.

35.0 Reference: Application, Tab F, Table 12.1
Power Smart and the Conservation Potential Review Study

Table 12.1 shows that the annual electricity consumption for 2005/06 in the Reference Case is 49,739 GWh per year. Please advise where this figure can be cross-referenced to other parts of the Application. If it cannot be cross-referenced, please reconcile this figure with the Total Firm Sales of 50,883 in Table A7.1.

36.0 Reference: Application, Vol. II, Tab H, p. 8, Table 2
Peak Demand Reference Case

Explain the difference between the F2006 Reference Case peak demand in the above-referenced Table compared to the peak demand as stated in the Application, Vol. I, Tab 4, Table 4-12.

37.0 Reference: Application, Tab F, Appendices 1 & 2
Price and Income Elasticities

Model 2 of the maximum likelihood estimates (With Gas) show that the effect of gas prices is counter-intuitive.

37.1 The analysis assumes that an increase in the price of natural gas would induce consumers to turn to electricity consumption. In the database used for the Model 2 econometric analysis, what are the percentage shares of:

(i) BC Hydro customers who possess existing fuel switching capability in space heating?
(ii BC Hydro customers who use only natural gas for space heating?
(iii) BC Hydro customers who use only electricity for space heating?

37.2 Please comment on whether, for the purpose of estimating price elasticities without counter intuitive results, the econometric analysis should have been based on weather normalized data that are also normalized by the number of households or floor space such that socio-economic effects are isolated from the time-series analysis.

38.0 Reference: Application, Tab F, Appendices 3 & 4
Weather Normalization

38.1 Please provide the basis for using the most recent 36 months of data to estimate weather-adjusted use rate for energy.

38.2 The Application states that weather normalization for energy is not undertaken for the commercial sector. Please provide the percentage share of commercial building or floor stock that has electricity space heating as end use.

38.3 Please justify the design temperatures of -6.8 degrees Celsius for the system and -4.4 degrees Celsius for Vancouver Island. Please comment on when the review of design temperatures will be completed.

39.0 Reference: Application, Tab F, Tables A3.1 and A4.1

39.1 Please provide the average annual growth (%) for the period 1993/94 to 2002/03 for energy and peak (actual and weather normalized).

39.2 Please provide the annual growth rates (energy and peak) for F2004, F2005 and F2006 for the reference forecast as well as the high and low forecasts.

39.3 Please explain the differences between the actual and normalized peak values for the BC Hydro Integrated System (Table 4.1) with the last column in Table 5-2 (page 29). Please provide the worksheets for the weather normalization of actuals for the total integrated system peak, including the substation system peak adjustments.

40.0 Reference: Application, Vol. I, Tab 1, Table 1-1, 1-3
Supply/Demand Overview

40.1 Table 1-1 shows that growth in domestic sales rose by an average 16 percent and peak one-hour demand grew by 5 percent between F1994 to F2003. Please provide any analysis that BC Hydro has undertaken to analyze the sales growth that might have been spurred on by increased purchasing power through the real decrease of 14 percent in rates since 1993.

40.2 Please reconcile the Total Domestic Sales Forecast for F2004, F2005 and F2006 in Table 1-3 with Total Domestic Sales and Total Firm Sales for the same years in Table A7.2 in Vol. II, Tab F.

41.0 Reference: Application, Vol. I, Tab 1, p. 1-15
New Customer Billing

The Application states that BC Hydro cannot apply new rates until the new customer billing is in place and fully functioning. Please describe the enhanced features of the new billing system.

42.0 Reference: Application, Vol. I, Tab 2, p. 2-6
Domestic Sales

Table 2-6 gives the breakdown and total domestic sales for financial purposes from F2003 to F2006. Please reconcile the figures in this table with the corresponding figures in Table A7.2 in Vol. II, Tab F.

43.0 Reference: Application, Vol. I, Tab 2, Schedules A5, 6, & 7
Revenues

43.1 Please extend the tables back to F2001.

43.2 Please show the calculations for Power Smart savings in $ millions.

POWER SMART

44.0 Reference: Application, Vol. I, Tab 8, p. 8-4 (lines 22 and 23)
Key Accomplishments

Identify the F2002 and F2003 components for business and residential customer energy savings of 334 GWh/year and 54 GWh/year, and cite the particular sections in Appendix M or Appendix I to verify these amounts.

45.0 Reference: Application, Vol. I, Tab 8, p. 8-5, Section 1.4

Performance Metrics and Benchmarking

Please supply the Cambridge Energy Research Associates Inc. and CEEA reports on BC Hydro's Power Smart program, and comment on the differences that led one organization to give "best-in-class" and the other to give "B+" evaluations.

46.0 Reference: Application, Vol. I, Tab 8, p. 8-6, Table 8.1
Operating Plan

46.1 Provide comment on the relatively few staff deployed in the residential sector as compared to the commercial sector in light of the comparable amounts of achievable savings in the two classes as identified in the BC Hydro Conservation Potential Review 2002 Summary Report.

46.2 (Lines 7 and 8) Provide a comparison for the program results of 1316 GWh/yr and 1769 GWh/yr against the corresponding values shown in the Application, Vol. I, Tab 4, Table 4-11, and explain any differences.

47.0 Reference: Application, Vol. I, Tab 8, p. 8-8, Table 8-4
Capital Expenditures

Comment on the difference in the F2003 capital spending as shown in the referenced Table against the amount shown in the Power Smart 10 Year Plan, page 21, Table 4-5 in Vol. II Tab I.

48.0 Reference: Application, Vol. I, Tab 8, p. 8-24, lines 20 to 23
New Energy Acquisition Contractual Effort

Supply a list of the 66 contracts referred to in line 23, and identify those referring primarily to supply of electrical energy. Please comment on why (or why not) these contract management costs should not be applied against the energy costs from those contracts in order to give a better true cost.

49.0 Reference: Application, Vol. II, Tab H
Sector Definition

Are the definitions for the Residential, Commercial and Industrial sectors in this report the same as the definitions for those sector classes as the terms are used in the Application, Vol. I, Tab 4 and Vol. II, Tabs I, M and N? If so, why has the commercial sector's Power Smart potential risen as compared to the residential sector from the starting point in Tab H to the potential described in Tabs I, M and N? If not, how have the definitions changed?

50.0 Reference: Application, Vol. I, Tab 4, p. 4-7, 8
Rate Impact Measure

The Application states that the proposed general rate increase is not likely to have an impact on DSM programs for large commercial and industrial projects, nor for small businesses and residential customers. Please comment on the Ratepayers Impact Measure (RIM) for the Power Smart programs (Appendix N) and the Power Smart programs' estimated impact on rates for F2005 and F2006.

51.0 Reference: Application, Vol. I, Tab 4, p. 4-5
Amortization of Power Smart before F2002

51.1 As of the end of F2001, the Power Smart program yielded energy savings of 2,459 GWh/year.

Please explain whether any of the programs from pre-F2002 will be sustained in F2004 to F2005 and describe the amount of energy savings that can be derived from these programs.

51.2 When will the Pre-F2002 Power Smart capital costs be fully amortized?

52.0 Reference: Application, Vol. I, Tab 4, pp. 4-5, 6,7, Table 4-11; Vol. II, Tab I, Tables 4-1 & 2 Power Smart since F2002

52.1 Please provide the basis for choosing 8 percent real discount rate on calculating life cycle costs in the CPR Update.

52.2 Table 4-11 shows that there is 280 GWh reduction in energy requirements due to Power Smart in F2004 and 1,375 GWh reduction in F2006. Please compare and explain these figures to the Portfolio Total figures for 2003/04 to 2005/06 in Table 4.1 and 4.2 in Tab I of Vol. II.

52.3 Please clarify to what extent the Power Smart since F2002 deviates from the CPR Update (e.g., by including specific peak demand reduction actions such as fuel switching and others).

52.4 Please provide the amortization rate and evidence of the expected life for each DSM program or if an amortization rate is applied by type of energy efficiency investment, please provide the amortization rate and evidence of the expected life for each type of energy efficiency investment.

53.0 Reference: Application, Volume I, Chapter 2, p. 2-17

53.1 BC Hydro states that it will change its accounting for costs associated with the retirement of capital assets as necessitated by a change in Generally Accepted Accounting Principles and the introduction of CICA Handbook Section 3110. Please provide a copy of Section 3110-Asset Retirement Obligations.

54.0 Reference: BC Hydro Application for a Net Metering tariff, Response to BCUC IR No. 1 Questions 12.1 and 12.2

BC Hydro has proposed in its application for a Net Metering Tariff that a four quadrant meter, which will record both the net kWh taken from BC Hydro and the net kWh generated into the BC Hydro system by the customer, be used.

54.1 To what extent is BC Hydro planning to change out standard electromechanical meters over time in favour of four quadrant meters to accommodate net metering?

54.2 Are there other new meter types that BC Hydro is considering installing on residential and commercial customer accounts, over time, to accommodate other potential new uses such as, for instance, time-of use metering? If so, what other types of meters are being considered and what types of customer applications are they intended to facilitate?

54.3 If BC Hydro is considering replacement of standard electromechanical meters with more sophisticated meters over time, what is the anticipated yearly cost of such replacements during the test period?

54.4 What potential impacts to customer rates will occur if the Net Metering proposal goes ahead? What specific aspect of the application will be affected by these impacts, if materialized?

55.0 Reference: Application, Vol. I, Tab 4, p. 4-7
Impact of Stepped Rates

The Application states that over the life of the 10-year plan, Stepped Rates will reduce the need for Power Smart incentive payments to Industrial customers by as much as $60 million (in nominal dollars).

55.1 Please explain how the $60 million is estimated.

56.0 Reference: Application, Vol. I, Tab 8, p. 8-2, 8; Vol. II, Tab M, p. 1-2
Power Smart

56.1 Some of the functions of the Power Smart Organization are to communicate to customers to practice demand side management and to assess energy efficient opportunities. Please clarify the role of BC Hydro vis-à-vis the role of suppliers of energy efficiency technologies (e.g., manufacturers and distributors) in educating customers and verifying savings.

56.2 BC Hydro designs programs to address the issue of awareness of energy efficient technologies by suppliers to overcome market barriers. Has BC Hydro made any attempt to partner suppliers and retailers to overcome the market barriers in order to reduce Power Smart program costs? If yes, please describe the extent. If no, please explain why not.

56.3 Please explain the basis of adopting a nominal 8 percent discount rate for the evaluation of the Power Smart 10-year Plan.

57.0 Reference: Application, Vol. II, Tab M, pp. 1, 2
Market Transformation

57.1 Please explain the importance of the market transformation programs in terms of their share in the overall investment cost and energy savings in Power Smart.

57.2 Please explain how the expected increase in Power Smart market penetration as depicted in Figure 1.1 is reflected in the end-use shares in the demand model.

58.0 Reference: Application, Vol. II, Tab M, Appendix D
DSM Evaluation

Please show the calculations for the following:

(i) Total Utility Cost of $314,662.90 as the sum of labour costs, incentives, etc.
(ii) Total Resource Cost of $601,226.20
(iii) Rate Impact Benefit Cost of 0.60
(iv) Utility Levelized Cost of $1.96
(v) TRC Levelized Cost of $3.74

59.0 Reference: Application, Vol. II, appendix I, pp. 3, 5
Cost Effectiveness

The Application states that the overall cost-effectiveness is considered most important at the portfolio of programs level rather than individual program or sector level.

59.1 Please explain the decision-making process to include an individual program that does not pass the cost-effectiveness test in the portfolio.

59.2 Please explain if the cost-effectiveness test is a factor in the allocation of $690.6 million portfolio investment cost to the industrial sector taking 39 per cent share, commercial taking 25 percent and residential taking up 16 percent. If it is not a factor, please explain why not.

60.0 Reference: Application, Vol. II, Tab I, p. 9
Line Losses

The Application states that for the purpose of calculating TRC and utility costs, line losses of 7 percent was applied to the residential sector, 7 percent to the commercial/government sector, and 3.6 percent to the industrial sector. Please explain the differences between these rates with the assumptions of 4 percent for Distribution and 8.1 percent for Transmission used in Tables A7.1-7.6 in Tab F of Vol. II.

61.0 Reference: Application, Vol. II, Tab I, Tables 4.1-4.8; p. 7
DSM Costs and Savings

61.1 Please re-state the above tables for F2003 to F2006.

	TOTAL BC HYDRO COST ($ M)	CUSTOMER COST ($ M)	TRC ($ M)	CUSTOMER SAVINGS ($M)	TOTAL ENERGY SAVINGS	PEAK SAVINGS
F2003						
F2004						
F2005						
F2006						

61.2 Please show the calculations for:

(i) levelized utility cost of $0.021/kWh
(ii) total resource cost of $0.044/kWh.

61.3 Please provide a copy of the BC Levelized Electricity Price Forecast (Oct/03).

62.0 Reference: Application, Vol. II, Tab I, Table 4.1; Tab M, p. 8
Energy Savings – Compact Fluorescent Lighting

Please provide a copy of the Evaluation Update (Nov 2003) and V.I. Impact Evaluation (Nov 2003) for the Compact Fluorescent Light Program. If the energy savings of 32 GWh as stated in Table 4.1 in Tab I are not confirmed in the Evaluation Update, please provide the applicable evaluation of the CFL program.

OMA EXPENSES

63.0 Reference: Application, Vol. I, Tab 8, pp. 8-27, 28
OMA Expenses

63.1 Please disaggregate the OMA expenses for the forecasting function into staffing, contracts for consulting, software costs, etc.

63.2 Please describe the role and responsibilities of the management headcount for the forecasting function.

64.0 Reference: Application, Vol. I, Tab 8, p. 8-23 (lines 19 to 22)
Load Forecasting Methodology

Please provide an explanation of the traditional load forecasting methodologies that were employed previous to 2003 and identify their shortcomings. Do the new methodologies require more staff, and if so, how many, and are their costs included in the $0.3 million increase in F2004 and F2005, and is this increase sustained in future years?

65.0 Reference: Application, Vol. I, Tab 8, p. 8-26, lines 24-28
Energy Management Services

65.1 Provide a summary of reliability planning assumptions and constraints, and provide details of recent revisions to those assumptions and constraints as implemented by this department.

65.2 Provide details of the roles of the additional resources referred to in this section, and their specific benefit in bringing transparency to the planning and load forecasting functions.

BCTC

66.0 Reference: Application, Vol. I. Tab 8, p. 8-26

Please describe the development of load forecasting function at BCTC and the past, current and future coordination activities between BC Hydro and BCTC. In future revenue requirement proceedings, will BC Hydro and BCTC each prepare a load forecast? Please describe the approaches, tools and methodologies that BCTC expects to use for its load forecasting function?

67.0 Reference: Application, Vol. I, Tab 6, p. 6-7, Table 6-1

67.1 Please confirm that BC Hydro's Transmission line of business/division/function existed during the period from F2000 through to F2004, inclusive.

67.2 Please confirm that total OMA costs, cost recoveries and non-WTS revenues pertaining to BC Hydro's Transmission line of business/division/function were separately accounted for during the period from F2000 through to F2004, inclusive.

67.3 If the answer to 1.1 and 1.2 is affirmative, please provide a schedule in the same format as Table 6-1. The schedule should be expanded to cover the years F2000 through to F2006. Furthermore, the schedule should list all the functional descriptions (e.g. System Operations, Asset Management & Maintenance, General & Administration, etc.) and other cost and revenue items (e.g. Depreciation & Amortization, Finance Charges, Cost Recoveries, etc.) contained in Table 6-1 and all additional functional descriptions and other cost and revenue items that were applicable for the years F2000 through to F2004 (and are presently not included in table 6-1).

67.4 For the schedule in 1.3, please provide the cost, cost recoveries and revenue amounts for each of the functional descriptions and other cost and revenue items for the years F2000 to F2006 (as applicable).

68.0 Reference: Application, Vol. I, Tab 6, p. 6-9, Table 6-2

Preamble: In Note 1 to Table 6-2 BCTC states that F2003 Costs are not available in the same categories as subsequent years due to accounting and restructuring changes that occurred post F2003.

68.1 With reference to 1.1 and 1.2, please prepare a schedule using the same format as Table 6-2. The schedule should be expanded to cover the years F2000 to F2006. Furthermore, the schedule should list all the functional descriptions and cost recoveries (e.g. Transmission System Operation, General and Administration, BC Hydro Corporate Allocation, etc.) contained in Table 6-2 and <u>all</u> additional functional descriptions and cost recoveries that were applicable for the years F2000 through to F2004 (and are presently not included in table 6-2).

68.2 For the schedule in 2.2, please provide the cost and recovery amounts for each of the functional descriptions and cost recoveries for the years F2000 to F2006 (as applicable).

69.0 Reference: Application, Vol. I, Tab 6, pp. 6-81 & 6-82, Table 6-26 & Table 6-27

69.1 Please provide the F2005 budget for the gross transmission costs, cost recoveries, other non-tariff revenues and return on equity as shown in Table 6-26 under the column headed "BCTC."

69.2 Please provide the F2006 budget for the gross transmission costs, cost recoveries, other non-tariff revenues and return on equity as shown in Table 6-27 under the column headed "BCTC".

69.3 Please provide a complete description of the budgeting process that led to the production of the F2005 and F2006 budgets referred to in 3.1 and 3.2. This should include a description of, e.g. the general budget guidelines issued, use of historic trends versus a zero based methodology, required approvals, etc.

70.0 Reference: Application, Vol. I, Tab 6, pp. 6-42 & 6-43, Figure 6-5 & 6-10

70.1 Please confirm that the positions in the Organizational Chart shown in Figure 6-5 and the FTEs shown in Table 6-10 reflect the positions and FTEs forecast for F2005.

70.2 Please expand the Organizational Chart shown in Figure 6-5 to include all managerial, supervisory, any other bargaining unit exempt positions and bargaining unit positions. With reference to Table 6-10 on page 6-43, please indicate on this expanded chart, the number of FTEs in each position.

70.3 Please provide an expanded Organizational Chart, as discussed in 4.2, for forecast F2006.

70.4 Please provide an Organizational Chart for the BC Hydro Transmission line of business/division/function, in a similar expanded format as discussed in 4.2, for each of the fiscal years F2000 to F2004, inclusive.

71.0 Reference: Application, Vol. I, Tab 2, p. 2-85, Schedule D4

71.1 Please expand this schedule to include the same information for the years F2000 to F2002.

71.2 Please confirm that the amounts shown in the "Headcount" subsection of Schedule D4 represent FTEs.

71.3 Please show as a separate category in the "Headcount" subsection of Schedule D4 (in the expanded format discussed in 5.1), all consultants/contractors on a full time equivalent basis.

72.0 Reference: Application, Vol. I, Tab 6, pp. 6-7, 6-11 to 6-13

72.1 Please confirm that the Total Transmission Revenue Requirement for F2005 and F2006 as shown in Table 6-1 does not include costs of any kind (e.g. direct, indirect or allocated capital and OMA costs, amortization expense, financing charges, etc.) pertaining to the System Control Modernization Project. If any costs are included please provide full details.

72.2 BCTC states on page 6-11, line 25 "As a result, BCTC is currently developing a strategy to address this significant issue." Please elaborate more fully on this strategy. When does BCTC expect to complete the development of this strategy?

72.3 The Network Operation Services department and the Network Performance Planning department were amalgamated to form the System Performance Assessment group (page 6-12).

Please discuss the benefits and dollar savings that resulted from this amalgamation, if any, and confirm that the dollar savings are reflected in the F2005 and F2006 Transmission Revenue Requirement. If dollar savings occurred but are not reflected, please provide reasons therefore.

72.4 BCTC states that the System Performance Assessment group performs studies to facilitate the interconnection of generators to the transmission system (page 6-12).

How are the costs for these studies recovered? Is there a sharing arrangement with generators? Please discuss in detail.

72.5 BCTC states that the Market operations group is responsible for maintaining BCTC's OASIS (Open Access Same-Time Information System) site (page 6-13).

Please provide additional information regarding OASIS. This should include, for example, information on the functionality of this system, BCTC's total annual OMA and sustaining capital costs pertaining thereto, any cost sharing arrangements with other users, how decisions re upgrades are made, etc.

72.6 The following information regarding OASIS was taken from BCTC's website:

OASIS FAILURE
Posted on January 21, 2004@0:20

BCTC is currently experiencing problems with OASIS, effective Jan. 21, 2004 @ 00:20 PST. The problem is at BPA OASIS site, BPA is investigating. As a result, Backup procedures will be in effect for Real-time and Preschedule until our system is restored. A subsequent bulletin will be posted when normal procedures can resume.

BCTC OASIS Service Restored
Posted on January 1, 2004@19:17

BCTC would like to inform that the OASIS outage declared on Jan 01/04 at 18:38, has been resolved and that access to OASIS has been restored to normal.

OASIS Failure
Posted on January 1, 2004@18:33

BCTC is currently experiencing problems with OASIS, effective Jan. 1, 2004 @ 18:30 PST. As a result, Backup procedures will be in effect for Real-time and Preschedule until our system is restored. A subsequent bulletin will be posted when normal procedures can resume.

72.6.1 Please discuss how frequent these failures are. Are they indicative of structural problems with OASIS?

72.6.2 Are any forecast costs related to the restoration of OASIS failures included in the Transmission Revenue Requirement for F2005 and F2006? If yes, please provide complete details.

72.6.3 The information above suggests that other transmission entities may be connected to/are using the OASIS system (e.g. BPA). Are the costs of restoration shared with other transmission entities? If not, why not?

73.0 Reference: Application by British Columbia Transmission Corporation for Approval of an Application for Deferral Accounts and Letter No. L-1-04

Preamble: BCTC applied for approval of the following deferral accounts:

a. Utilization and Credit Risk Deferral Account
b. an Emergency Maintenance Expenditure Deferral Account
c. a Cost of Market Deferral Account, and
d. a Regulatory Expenditures Deferral Account

73.1 Utilization and Credit Risk Deferral Account:

On page 4 in the above Application, BCTC states it "does not seek deferral treatment for revenue variances attributable to imprudent administration of its Transmission tariff, including credit and collection procedures, or imprudent operation of the transmission system."

Please provide your comments about the type of process you envisage that would lead to the determination of the imprudent component, if any, of the expenditures in question.

74.0 Reference: Application, Vol. I, Tab 6, p. 6-84
Amending WTS Rates

74.1 The Application indicates that the maximum PTP rate will change from $4.68 per kW-month of reserved capacity to $4.62 per kW-month in F2005. Please provide the data and calculation that establish the increase in available capacity.

74.2 The Application proposes to amend the RS 3003 tariff to reflect the estimated cost to provide this service. Please provide the historical costs (F2001-F2003) and planned costs (F2004-F2005) for this service.

75.0 Reference: Application, Volume I, Chapter 3, pp. 3-3 to 3-5; Chapter 6, p. 6-42
Budget Process and Variance Analysis

Section 2 of Chapter 3 describes how the F2005 and F2006 OMA and capital spending forecasts used in the Application were developed.

75.1 Please provide a copy of the Situation Analyses that were developed by August 2003 by each line of business as described in Section 2.2.

75.2 Please identify the strategic objectives of BC Hydro and the objectives of the lines of business that were approved by the Board at meetings on September 20 and 21, 2003. Please explain how the strategic objectives of BC Hydro were applied to define the strategic objectives of each line of business.

75.3 One of the key components of the strategic objectives for F2005 and F2006 identified in Section 2.2 is improved service quality. Please demonstrate how the Situation Analyses evaluated the current level of service quality, identified a target level of service quality and how the performance targets were set in capital and OMA to achieve target service quality in a fiscal year or over multiple years.

75.4 Please identify the performance targets that were established for F2005 and F2006 for the lines of business and the corporation as a whole. Please provide a copy of the guidelines that were generated by corporate office and provided to the lines of business on September 30, 2003 regarding the development of performance targets.

75.5 Based on the organization chart in Schedule 1-1, page 1-25 it appears that the Vice-President level corresponds to the line of business structure. The organization chart for BCTC is shown in Figure 6-5, page 6-42. At the Workshop on January 15, 2004 BC Hydro was advised that budgets and variance analysis would be requested that are one or two management levels down in each line of business.

For F2005 and F2006, the director/manager levels shown on the BC Hydro organization chart should provide an acceptable level of detail. Please provide an equivalent director/manager level for BCTC for F2005 and F2006. Please provide the F2005 and F2006 OMA and capital budgets at the director/manager levels for each line of business in BC Hydro and BCTC and the corresponding roll-up to the line of business totals as shown in the Application.

75.6 For F2003 and F2004 please provide the OMA and capital budgets and variance analysis at the same director/manager level as the question above. If a reorganization occurred in either F2003 or F2004, please provide an organization chart, the budgets and variance analysis at the appropriate level of detail and the corresponding roll-up. Please provide the F2003 and F2004 performance targets for these director/manager and senior levels and identify the corrective action that was taken when unacceptable variances occurred.

75.7 If a reorganization occurred in F2000 to F2003 inclusive, please provide a business case in support of the reorganization.

75.8 For F2003 and F2004 please explain the frequency of OMA and capital budget variance analysis and the level of detail in the variance analysis.

75.9 For F2003 and F2004 please provide a list of the reports that were prepared throughout the period by the Senior Executive and Direct Reports as shown on the organization chart on Schedule 1-1 or the appropriate organization chart for that fiscal period.

75.10 The BC Hydro Annual Reports to the Commission for the years ending March 31, 2002 and 2003 included Attachment E which lists the internal audits completed in that year. Please provide a copy of each of the internal audit reports listed in Attachment E for March 31, 2002 and 2003.

76.0 Master Agreement, p. 13

76.1 Please provide the BCH Owner's Revenue Requirement as set forth in the subsections of section 4.7 of the Master Agreement for F2004, F2005, and F2006.

76.2 Please provide the BCTC Revenue Requirement for F2004, F2005, and F2006 as set forth in subsection a, b, and c of section 4.8 of the Master Agreement.

76.3 Please provide the forecast costs for the Asset Management and Maintenance Services as set forth in section 4.9 of the Master Agreement for F2005 and F2006.

76.4 Please provide a copy of the Transmissions System capital plan provided by BCTC to BC Hydro pursuant to subsection 4.11(c) of the Master Agreement.

76.5 Pursuant to subsections 4.13(d) and (e) of the Master Agreement, does BC Hydro assume the load forecast risk related to the recovery of the BCH Owner's Revenue Requirement in the absence of approved deferral accounts that are satisfactory to BCTC? If not, please explain?

76.6 In the absence of the approval of deferral accounts contemplated in subsection 4.13(f) of the Master Agreement, does BC Hydro assume the load forecast risk arising from a load forecast prepared and presented to the Commission by BCTC? If not, please explain?

76.7 Please provide a copy of any Depreciation Studies or any other studies provided to BC Hydro by BCTC pursuant to section 4.15 of the Master Agreement.

76.8 Do either BC Hydro or BCTC intend to seek Commission approval for the agreements referred to in the Master Agreement to be entered into by April 1, 2004 [see section 7.4(a), 8.3(b), 8.3(c), 11.3(a), 12.2(a) and the Support Services Agreement to be entered into by April 1, 2004(see section 3.1)]? Please provide a forecast for F2005 and F2006 of the amounts to be paid pursuant to such agreements.

76.9 Please provide the amount of the funding obligations, of BC Hydro under the RTO West Funding Agreement as set forth in section 10.1 of the Master Agreement.

76.10 Please provide a copy of each budget referred to in 18.2 of the Master Agreement.

76.11 Internal Audit

Please provide a copy of the current internal audit plan.

77.0 Reference: p. 9-42, line 17-22, and B1-1, Tab 9, p. 42, Inventory

77.1 Please provide a definition of the inputs into the inventory turnover metric shown in Table 9-14 and the source for the Target and the calculation of the Actual/Forecast. Is the target calculated based on the target stock levels referred to at page 9-42, line 19?

77.2 Please provide a description of BC Hydro's inventory accounting systems, including frequency of physical inventory counts, warehouse records, and criteria for obsolence provisions.

77.3 Please also identify all inventory turnover metrics used by management and the past five year actuals for each metric. Please also provide comparisons to appropriate benchmarks for each metric.

77.4 Please explain the difference between the loading rate of 29 percent referenced on page 9-41 and the actual loading rate ranges between 10 and 25 percent on page 9-42.

78.0 Reference: Schedule A-2, p. 2-41

78.1 Please provide a copy of BC Hydro's most recent depreciation study.

78.2 Please provide the amortization rate and evidence of the expected life for each DSM program or if an amortization rate is applied by type of energy efficiency investment, please provide the amortization rate and evidence of the expected life for each type of energy efficiency investment.

79.0 Reference: Schedule A-4, p. 2-43

79.1 Please provide the schedule of sinking fund payments by debt instrument.

80.0 Reference: Schedule D1-1, p. 2-79, Line 13 and Line 14

80.1 Please provide details of the current capitalized overhead policy and recoveries and identify any changes in F2003 and F2004.

81.0 Reference: Schedule D4, p. 2-85, Line 17 and Line 19

81.1 Please breakout the Direct and Corporate Allocations for F2003 by the budget line items approved for F2005 and F2006 and provide the budget line items for F2005 and F2006. Please provide a further description of the amounts shown as Corporate Allocations for F2005 and F2006; for example, what transmission related function is BC Hydro performing; please explain why these functions could not be provided by BCTC to BC Hydro, so that it is not necessary for BC Hydro to incur these costs directly. If those functions or services are contemplated in the Master Agreement or Key Agreements, please provide references. What is the total amount of

BC Hydro "BC Hydro Corporate Direct Charges" and the total amount of BC Hydro "Corporate Allocation"? Please describe the allocation methodology.

82.0 Reference: Schedule D10, p. 2-91

82.1 Please review line items 31-33 and correct as appropriate or provide the appropriate breakdown of line 34.

83.0 Reference: Schedule 1-1, p. 1-25

83.1 Please show the full complement and the active employees for each "box" shown on the organization chart, and please "map" each "box" on the organization chart to the "D" Schedules at the end of Tab 2 or provide an organization chart for each "D" Schedule.

84.0 Reference: 'D' Schedule, also Schedule 9-5, Note 1 and Note 4

84.1 Please provide a description of the human resources policy for determination of salaries, wages, including gain sharing and incentives, and benefits for M&P, IBEW, and OPEIU. Please provide the metrics used for the management incentive program, if any.

85.0 Reference: Schedule 9-3, p. 9-70, Schedule D9, p. 2-90, and p. 9-28, Lines 13-14

85.1 Please explain the objectives for Maintenance Services that supports the year over year increase from F2004 to F2005 shown on Schedule 9-3, and explain the work programs for delivery of such services given the decrease in Headcount shown on Schedule D9.

86.0 Reference: Work Plan Completion, p. 9-35 and p. 9-28, Line 14

86.1 Please provide the completion percentage of maintenance work and capital construction work programs for each of the past three years.

87.0 Reference: Table 7-4, p. 7-20, p. 9-28, lines 20-22 and p. 9-32, Lines 1-3

87.1 Please confirm whether or not Field Services has been able to respond to 80 percent of emergent calls in less than one hour for urban areas or has been able to respond to 80 percent of emergent calls in less than two hours for rural areas. Please also confirm what BC Hydro's goal for transmission and distribution is, is it the same goal.

88.0 Reference: P. 9- 35, section 3.5.3, Schedule 9-7, p. 9-73

88.1 Please provide a breakdown of the "Loadings for Management, Admin, Training & Other" and the target for the end of the fiscal year F2005 and F2006 for each line item identified. Please provide details of any management incentives that are determined based on performance against those targets.

89.0 Reference: P. 9-32, lines 4-6

89.1 Please provide the vehicle utilization percentages for the past three years and the performance target for F2005 and F2006.

90.0 Reference: Schedule 8, p. 9-73

90.1 Please provide benchmarks, if available and targets for total labour utilization for Regular and CBU set forth in Schedule 8. Please provide details of any management incentives that are determined based on performance against those targets.

91.0 Reference: Schedule D4, p. 2-85, line 30 and p. 2-29

91.1 Please provide an organization chart for the Transmission function in F2003 showing the total headcount of 228 by functional area and an organization chart for the Transmission function before and after the establishment of BCTC for F2004 showing the total headcount of 316 by functional area. Please confirm that for F2003, the headcount only includes active staff recorded as of March 31, 2003.

92.0. Reference: Chapter 9, 8.2.1, p. 9-57

In the Fall of 2001, BC Hydro undertook an internal study to identify, explore and validate the basis of differentiating activities between core and non core utility services along with its objectives in considering an outsourcing arrangement. Please provide a copy of this internal study and any other business case or evaluation material that was utilized in the justification of proceeding with the Accenture contract.

93.0 Reference: ABS (B1-1, p. 9-58, section 8.2.2)

93.1 Please provide a copy of the section(s) of the agreement with ABS that identify the services to be provided by ABS to BC Hydro and BCTC.

94.0 Reference: Table 9-23, p. 9-59

94.1 Please provide a description of the services provided by ABS to each functional area identified in Table 9-23. For each service provided, please provide the applicable costs.

94.2 Please provide the spreadsheet calculation of the total minimum aggregate spend of $1,282 million (nominal dollars) over the 10 year period.

94.3 Please file a copy of the legislation, including subordinate legislation, applicable to the ABS contract.

94.4 Please provide the contract references to the Master Agreement or Key Agreements, whichever is applicable, for the restructuring costs identified on page 2-20 and page 2-64(Note 3) and provide a breakdown of the F2003 and F2004 restructuring costs.

95.0 Reference: Application, Chapter 2 , 7.3 p. 2-38, p. 2-39; D Schedules pp.2-79 to 2-91; Chapter 9, Table 2-22, 8.6 p9-67,1 p.9-59 Table 9-23

Section 7.3 states that in F2003, a portion of the depreciation expense on capital assets used in the provision of support service was charged via loadings to the applicable business unit. With the implementation of the ABS contracts, this depreciation cost is loaded onto the base cost. Table 2-22 shows the fully loaded ABS costs that include both OMA and capital expenditures. Table 9-23 provides a summary of the ABS Baseline OMA costs by functional area. The Resource usage on the D Schedules shows the allocation of ABS services from F2003 to F2006.

95.1 In order to provide comparability to the allocations both pre- and post-ABS implementation please provide the following schedules:

- expand Table 9-23 to include the OMA costs by functional area by year for F1999 to F2003.
- provide a schedule of capital assets used in the provision of support services, its related depreciation expense and the allocation by lines of business and service organizations as identified in Table 2-22 for the years F1999 to F2003. The schedule should also identify the asset-related expenses that are allocated to the lines of business and service organizations for the years F1999 to F2003.
- prepare a schedule that demonstrates how the allocation of OMA and capital expenditures and asset-related loadings from F2003 were converted into the Table 2-22 F2004 base and loadings for the lines of business and service organizations.
- prepare a schedule that reconciles the base and loadings in Table 2-22 to the D Schedules by Resource Usage on pages 2-79 to 2-91.

96.0 Reference: Chapter 9, 8.4.1, p. 9-61, 8.4.7, p. 9-65

Identify the guaranteed savings for F2004 through F2006 inclusive, both in dollars and percentage for each of the identified functional units. Show how these guaranteed savings translate to the positive contribution to BC Hydro's net income of $2 million - F2004, $8 million - F2005, $12 million - F2006.

97.0 Reference: Chapter 9, 8.3.3, p. 9-60, 8.4.1, p. 9-61

BC Hydro's approved F2003 Shared Service Budget is the starting point for the determination of ABS baseline costs of $155.7 million. This F2003 baseline is set both for costs as well as the level of service for the next 10 years with guarantee savings.

97.1 Is BCH entitled to guaranteed savings for projected growth above the F2003 baseline level of service?

97.2 How are incremental and incidental services that are not included in this baseline charged back to BCH by ABS?

98.0 Reference: Chapter 9, 8.4.4, p. 9-64

A $44.4 million allowance for contingencies and additional work is included for the term of the ABS contract over and above the $155.7 million.

98.1 Identify the amount of contingencies and additional work for F2004, F2005 and F2006.

98.2 Specify the functional areas where the contingency and additional work would be applicable.

98.3 Provide detail of the work / projects that total to the allowances for each of these years.

99.0 Reference: Chapter 9, 4.6, p. 9-62

Up to $30 million of the Northstar investment is to be recovered by BCH, if ABS grows its business with this new customer information system to other external customers.

99.1 How much is the investment recovery anticipated for F2004, F2005, F2006?

99.2 Specify the recovery portion attributed to the capital investment and the ongoing costs for sustainment of this new customer information system for F2004, F2005, and F2006.

99.3 BCH expects half of the $15 million in customer information system benefits enhancements would be of value.

- Specify the timeframe ABS is committed to spending the $15 million in enhancing the base Northstar system.
- Identify the CIS benefits that would be of value to BCH from this enhancement.
- Specify the amounts these benefits would contribute to the F2004, F2005 and F2006 years.

100.0 Reference: Chapter 9, 8.4, p. 9-62

What is the anticipated revenue stream for "Founding Partner Benefits" for the F2004, F2005, and F2006?

101.0 Reference: Chapter 9, 8.3.2, p. 9-60, Table 9-24

Table 9-24 shows the opening balance of the transferred assets to BCH Services Asset Corp (SAC) as at April 1, 2003 at the Net book value of $188.7 million.

101.1 Extend this table to show the capital additions anticipated for F2004, F2005, and F2006 in the similar categories.

101.2 BCH SAC is responsible for funding any capital purchases required to maintain the capacity of the initial asset pool transferred as well as any new assets required to support incremental service level by ABS.

- What controls and measures are in place to ensure that the capital acquisitions especially in the IT functions, recommended by ABS are prudent and with exclusive interest for BCH needs and requirements?
- If ABS grows its business with external customers and utilizes BCH SAC's asset to gain economies of scale, what is BCH's portion of revenue recovery or costs sharing mechanism?

102.0 Reference: Chapter 9, 8.5, p. 9-65

102.1 Provide the external benchmarking studies conducted by META Group that indicates that organizations typically spend between 5 percent and 7 percent of their minimum aggregate spending to manage their outsourcing agreements.

102.2 Indicate how BCH has determined that management of ABS' contract would represent 2 percent of the annual minimum spend. Provide a cost breakdown for F2004, F2005, and F2006.

103.0 Reference: Chapter 9, Line 20, p. 9-65, Chapter 3, Table 3-24, p. 3-41

Table 3-24 shows the net OMA and headcount for the newly created Outsourcing & Contract Management.

- Identify the net OMA costs for F2004 forecast.
- Itemize the OMA costs by major costs categories, i.e. salary, benefits, loading, etc. for F2004, F2005, and F2006.

104.0 Reference: Chapter 9, 8.5. Line 27, p. 9-65

Provide the quartile service level management reports created to track actuals to target service level metrics and trends. This is part of the governance process to managing the service captured in the ABS contract.

105.0 Reference: Table 9-25, p. 9-67, Table 9-27, p. 9-68

($ millions)	**F2004**	**F2005**	**F2006**
Fully Loaded ABS costs	209.3	204.8	194.7
Minimum Aggregate Spend	147.3	137.9	131.0
Total Loadings	62.0	66.9	63.7
Percentage of MAS	42%	49%	49%

Identify and discuss the loading increases in F2005 and F2006 as compared to F2004.

106.0 Reference: Application, Volume 1, Tab 7, Section 2.7.2.4, Revenue Metering

The application states that Revenue Metering designs a life cycle 'cradle to grave' plan for each metering application.

106.1 What percentage of residential and commercial customer accounts are measured using standard electromechanical meters?

106.2 What is the approximate cost, or cost range for such meters?