

**British Columbia Hydro and Power Authority
Calls for Tender for Capacity on Vancouver Island**

BCOAPO Information Requests – Round 1

1.0 Reference: CFT Main Report, pages 3 (line 16) and page 12 (lines 28-29)

1.1 Please provide copies of any analyses or reports prepared by/for BCH to support the view that BCH did not need to include in the evaluation methodology a “risk premium” for projects adopting the “gas tolling option”?

2.0 Reference: CFT Main Report, page 4, (lines 5-7) and page 5 (lines 17-21)

2.1 Please outline what role, if any, the IR (Independent Reviewer) played in determining which comments or issues raised by parties regarding the original CFT would be addressed in the revised CFT issued on January 13, 2004.

3.0 Reference: Appendix F and CFT Main Report, page 7, Table 2

3.1 In its January 23rd, 2003 letter the BCUC noted that “Many parties feel that the CFT was structured to favour gas-fired generation, particularly a facility like VIGP”. Did BCH incorporate any changes in the revised CFT to address this concern and, if so, please outline what they were?

3.2 In its January 23rd, 2003 letter the BCUC stated that “BC Hydro should not expect that a transmission deferral credit will be accepted by the Commission Panel”. Would the retention of a transmission deferral credit, as originally proposed by BCH, have altered either:

- The Tier 1 results or
- The relative cost-effectiveness results for Tier 1, Tier 2 and No Award as set out in the Base Case in Table 6 (page 18)?

4.0 Reference: CFT Main Report, page 8, lines 14-18

4.1 Please indicate which of the Mandatory Criteria (as per Section 9.8 of the CFT) each of the three bids failed to meet.

**5.0 Reference: CFT Main Report, page 8 (lines 10-11) and page 8 (lines 28-29)
Appendix K, IR Report #4, page 13**

5.1 Of the ten proposed projects, please indicate how many of them were “VIGP projects.”

**Reference: CFT Main Report, page 8 (lines 10-11) and page 9 (lines 3-10)
Appendix K, IR Report #4, page 13**

5.2 For the final four Tenders, which included 5 natural gas projects, how many of the projects were “VIGP projects”?

7.0 Reference: CFT Main Report, page 9 (lines 13-15)

7.1 Please provide a copy of Table 6 from BC Hydro’s October 2003 Load Forecast.

8.0 Reference: CFT Main Report, page 11 (lines 13-16)

8.1 Please clarify, based on this paragraph, what gas transportation cost assumptions were used in the QEM in the case of gas-fired projects with dual fuel capability, e.g., were firm transportation prices used?

9.0 Reference: CFT Main Report, page 12 (lines 10-11 and lines 18-19)

9.1 BCH states that it “is active in monitoring gas and electricity prices.” Please provide copies of all reports and studies regarding future natural gas prices that BCH has prepared internally, commissioned or obtained in last 12 months.

9.2 Please provide a schedule contrasting the projected prices for natural gas from each of these sources with the forecast BCH prepared based on the EIA’s January 2004 Reference Case forecast. Please identify all assumptions and factors impacting on the comparability of the natural gas price forecasts provided in the schedule.

10.0 Reference: CFT Main Report, pages 13 (lines 31-32) and 23 (Table 8)

10.1 Please re-state Table 8 in \$2003 consistent with Table 6.

10.2 Please clarify the basis of comparison that gave rise to the \$50 M saving – prior to any allowance for the VIGP assets - referenced on page 13: i.e., was the Net Portfolio cost of the winning CFT portfolio used in the comparison and was it compared with the Total Tender Cost of the VIGP benchmark?

11.0 Reference: CFT Main Report, page 13 (lines 28-29)

11.1 Please indicate the level of savings (i.e., the difference in NPV) between the winning CFT portfolio and the next lowest cost Tier 1 portfolio.

11.2 Please confirm whether the next lowest cost (Tier 1) Portfolio involved:
a) a VIGP election
b) a Full Tolling or Partial Tolling election.

12.0 Reference: CFT Main Report, page 14 (lines 29-31))

12.1 Please indicate whether the peak experienced in 2004 and being compared with the value for 2007 (contained in the 2002 forecast) is the “actual peak” or a “weather normalized peak”. If the former, please provide the comparison after weather normalization.

13.0 Reference: CFT Main Report, pages 14 (line7) & 17 (lines 10-19) and Appendix J, page 2

13.1 Are the contingency plan options referred to on page 14 of the Main Report the Demand Management Proposal submitted by Norske Canada and the Temporary Generators as described in Appendix J?

13.2 Reference is made on page 17 to a “suite of contingency measures”. Are there any other “contingency options” available to BCH for the winter of 2007/08? If so, please describe what they are including details regarding capacity available, energy capability and costs.

13.3 Has BCH confirmed with Norske Canada that its Demand Management Proposal is still valid and can provide 240 hours of relief? If so, how recently was this done?

14.0 Reference: CFT Main Report, page 15, Tables 4 and 5

14.1 Please provide the specific cross-references to Appendix I (2004 Load Forecast) indicating where the Peak Demand forecasts shown in Tables 4 and 5 can be found.

14.2 The text (line 11) indicates that the dependable capacity resources shown in Tables 4 and 5 are based on a “single planning contingency standard”. Please indicate the megawatt value of the “single planning contingency standard” and how it has been factored into Table 5, which appears to simply list the capability of individual supply resources.

14.3 Please confirm that the peak demand values shown in the table are based on the average coldest day as opposed to an extreme coldest day (e.g., single coldest day in 10 years).

14.4 Please indicate by how much the Vancouver Island 2004 peak demand forecast would increase if based on an extremely cold day (e.g., the single coldest day in 10 years) as opposed to the average coldest day.

15.0 Reference: CFT Main Report, page 16 (lines 20-30)

- 15.1 Please explain how the cost-effectiveness analysis incorporated cost and time certainties/uncertainties (see lines 29-30) and describe the cost and timing uncertainties attributed to each of the three cases (i.e., Tier 1, Tier 2 and No Award).
- 15.2 What was the “cost-effectiveness standard” (see lines 20-22) established for the Tier 1 bids in the CFT?

16.0 Reference: CFT Main Report, page 17 (lines 2-9 and 22-30)

- 16.1 Please provide tables equivalent to Table 5 showing the supply/demand capacity balance for Vancouver Island for each of the three cases considered in the Cost Effectiveness Analysis. Please include the new 230 kV AC cable in the tables with the timing updated as required to reflect BCTC’s response to BCUC request as per Transcript page 310.
- 16.2 Please provide tables equivalent to Table 5 showing the supply/demand energy balance for Vancouver Island for each of the three cases considered in the Cost Effectiveness Analysis. Please include the new 230 kV AC cable in the tables with the timing updated as required to reflect BCTC’s response to BCUC request as per Transcript page 310.

17.0 Reference: CFT Report, Appendix J, pages 2 & 4 and CFT Main Report, page 17 (line 23-30) and page 18 (Table 6)

- 17.1 Please confirm that the two electricity price scenarios used 100% and 90% of the unit cost of production for the Tier 1 CFT – excluding the firm gas transportation costs. If not, please describe the basis for the price scenarios.
- 17.2 Please discuss why it is reasonable to assume for the Base Case (as shown in Table 6) that mainland generation would cost the same as generation constructed on Vancouver Island (excluding firm gas tolls).
- 17.3 Was the same mainland electricity price used to evaluate all three cases or were independent prices determined for each case based on the anticipated operation of the mainland generation to meet the additional energy requirements? In either case, please produce a schedule setting out the cost(s) of mainland electricity used for each case and, if different forecasts were used for each case, please explain the factors leading to the differences. (Note: If the absolute values can not be provided for reasons of confidentiality please explain why this is the case and provide the price differential for the three cases)

- 17.4 Please confirm the basis for the electricity price forecast used to value energy losses and energy volume differences prior to 2010. Was it an EIA electricity price forecast (as suggested in Appendix J, page 2 – last paragraph)? If so, please provide the forecast. Alternatively, was it a BCH-prepared electricity price forecast based on the EIA gas price forecast (as suggested in Appendix J, page 2 – first paragraph)?
- 17.5 Please explain why a different approach to valuing electricity energy differences between the three cases was used for the period prior to 2010 (which uses electricity price forecasts corresponding to the EIA gas price forecast - Appendix J, page 3) versus after 2010 (which uses the uses prices based on a Tier 1 CFT plant – Appendix J, page 2).
- 17.6 Please confirm whether the Base Case shown in Table 6 assumes:
- A new cable in-service date of 2009 – as per page 17 of the CFT Main Report, or
 - A new cable in-service date of 2010 – as per Appendix J, page 2 (last paragraph).
- 17.7 Attachment A of Appendix J contains a Table setting out the number of required Temporary Generators for each of the three cases. Please indicate the in-service date assumed for the new 230 kV AC cable in preparing the Table. If required, please update the Table to reflect BCTC's response to the BCUC request as per Transcript page 310.

18.0 Reference: CFT Main Report, pages 21-22

- 18.1 Was an incremental rate impact analysis conducted for either the Tier 2 or No Award cases? If so please provide the results in a format similar to Figure 2. If not, please provide a comparable rate impact analysis for the No Award case.

19.0 Reference: CFT Main Report, page 24 (lines 11-13)

- 19.1 Has BCH performed any independent assessments regarding the likelihood that Duke Point Power will not meet the scheduled in-service date? If so please, provide.
- 19.2 What are BCH's contingency plans for Vancouver Island supply in the event of a one-year delay in the in-service date for the Duke Point Power facility?
- 19.3 Are the financial penalties that would be assessed against Duke Point Power for not being in-service for the winter of 2007/08 sufficient to pay the incremental costs associated with the contingency plans BCH would required to implement to maintain the supply/demand balance on Vancouver Island?

20.0 Reference: CFT Report, Appendix B

- 20.1 Please explain how the “allocation of fuel risk” (see Item 6.2) was considered in the tender evaluation.
- 20.2 With reference to Item 6.2 and Addendum 10 (Appendix G), how many of the five natural gas projects that were considered in the development of the final 5 portfolios (see Report 4 of the IR, page 13) opted for:
- a) No Tolling
 - b) Partial Tolling
 - c) Full Tolling?
- 20.3 Which Tolling option did Duke Point Power opt for in its bid?
- 20.4 With reference to Item 6.3, in the event that Duke Point opted for either the Partial or Full Tolling option, has BCH received a firm commitment from TGVI with respect the cost of firm transportation?
- 20.5 If the answer to 20.4 is “no,” then:
- a) How sensitive is the selection of Duke Point Power as the preferred Tier 1 option to changes in the tolls for firm transportation service associated with the project?
 - b) Please perform a sensitivity analysis of Tier 1 versus Tier 2 versus No Award (as per CFT Main Report, Table 6) assuming a 20% increase in TGVI’s tolls for firm transportation service.
- 20.6 With respect to Item 7.6, does BCTC guarantee its Network Upgrade cost estimates? If not, then:
- a) How sensitive is the selection of Duke Point Power as the preferred Tier 1 option to changes in the Network Upgrade costs associated with the project?
 - b) Please perform a sensitivity analysis of Tier 1 versus Tier 2 versus No Award (as per CFT Main Report, Table 6) assuming a 30% increase in Network Upgrade costs for Duke Point Power? (Note: If BCTC guarantees for its costs estimates involve a different ceiling, please substitute the BCTC value in the analyses)
- 20.7 With respect to Item 11.3, is the Duke Point Power project dispatchable or must-run? If the former, is it Non-Peaking or Peaking Capacity? If the later, is it must run at Full Capacity or with a Minimum Turndown Capacity?

21.0 Reference: CFT Report, Appendix H and CFT Main Report, Table 3

- 21.1 With respect to Item 3.4.6, please provide a schedule setting out the derivation of 8% as BCH’s current weighted average cost of capital.

21.2 Please provide the total NPV calculated for the Duke Point Power Project broken down into the following cost components:

- Capital Charges
- OM&A Charges
- Energy Margin – broken down to separate the portion based on the average Forecast Electricity Prices and the portion based on Tender Variable costs.
- Start-Up Costs
- Firm Gas Transportation (if Partial or Full Tolling)
- Gas Costs (if Full Tolling)
- Network Upgrade Costs
- VIGP Credit

(Note: If the above components do not account for the full NPV of the Duke Point Power portfolio's NPV please add the missing elements as separate items)

22.0 Exhibit B-6, Duke Point Power Electricity Purchase Agreement

22.1 Based on the terms of this agreement and the assumptions regarding the operation of Duke Point Power's generation used in the Tender/Portfolio evaluations, please provide a schedule setting out for the duration of the agreement:

- a) the annual amount energy BCH expects to purchase from Duke Point Power over the duration of the agreement, and
- b) the annual amounts payable to Duke Point Power for that energy in total and broken down into the following components:
 - the CC Payment
 - the OMC Payment
 - the EC Payment
 - the Start-Up Payment, and
 - Availability Adjustment (if assumed applicable).

22.2 Based on the terms of this agreement and the assumptions regarding the cost of gas and operation of Duke Point Power's generation used in the Tender/Portfolio evaluations, please provide a schedule setting out for the duration of the agreement:

- a) the annual natural gas requirements of the Duke Point Power generation facility,
- b) the annual amounts payable for by BCH for the natural gas supplied to the Duke Point Facility (assuming Full Tolling),
- c) the annual amounts payable by BCH to TGVI for gas transportation service to the facility (assuming Full or Partial Tolling), and
- d) the annual amounts payable by BCH to other parties for gas transportation service to the facility (assuming Full or Partial Tolling).

22.3 In the event that Duke Point Power has elected for either Full Tolling or Partial Tolling, where does the agreement address BCH's obligations with respect to gas transport (and commodity supply, if applicable)?