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Log No. 7683

VIA E-MAIL

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December 8, 2004

Mr. Richard Stout
Chief Regulatory Officer
British Columbia Hydro and Power Authority
17th Floor, 333 Dunsmuir Street
Vancouver, B.C. V6B 5R3

British Columbia Hydro and Power Authority
Call for Tenders for Capacity on Vancouver Island
Review of Electricity Purchase Agreement

Exhibit No. A-9

Dear Mr. Stout:

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Call for Tenders for Capacity on Vancouver Island ("CFT")
Review of Report on the CFT Process dated November 19, 2004 ("CFT Report")
Commission Information Request No. 2

Attached please find Commission Information Request No. 2 to BC Hydro regarding the CFT Report and the review of the Electricity Purchase Agreement. Please provide a hard copy and an e-mail file in response by Friday, December 17, 2004. Please provide a copy of the response to this Information Request to all Intervenors.

Yours truly,

Original signed by:

Robert J. Pellatt

JBW/rt
Attachment

cc: Registered Intervenors

BRITISH COLUMBIA UTILITIES COMMISSION
Commission Information Request No. 2 (Non-Confidential)

**British Columbia Hydro and Power Authority (“BC Hydro”)
Call for Tenders for Capacity on Vancouver Island (“CFT”)
Review of Electricity Purchase Agreement (“EPA”) Filing dated November 19, 2004**

Note: “EPA” refers to the final form EPA (Exhibit B-1, Tab N), unless otherwise indicated.
“INRV” refers to the Independent Reviewer
“DPPLP” refers to Duke Point Power Limited Partnership

45.0 Reference: CFT Report, pp. 14, 16, Section 3.2

The Filing states that the acquisition of 252 MW as a result of the CFT addresses 95% of the shortfall, and less with the pending load forecast revision. On page 14 the Report states that the forecast will need to be revised upward to reflect the actual rate increase approved by the Commission, thereby increasing the deficit on Vancouver Island.

- 45.1 Does BC Hydro plan to revise the peak demand forecast for Vancouver Island on the basis of price elasticity as reported in Appendix 2 in Appendix I of the Report? If no, please explain how BC Hydro proposes to revise the forecast.
- 45.2 If the revision is to be based on the peak elasticities estimated in Table A2.1 in Appendix I, please comment if Model 1 (Without Gas) provides a significant coefficient for log electricity price. Please explain your answer.

**46.0 Reference: Exhibit B-1, Appendix J; Appendix K, Tab 4
Exhibit No. A-5, BCUC IR 14.0, 29.0**

- 46.1 Page 13 of the Fourth Report of the Independent Reviewer appears to state that the “no dual fuel” project from Tender D failed the Conformity Review. Please explain the specific criteria that it failed to meet, and the deficiencies of the project that resulted in failure. Why did the dual fuel project pass these criteria?
- 46.2 Please repeat the foregoing question for the projects in Tender F.
- 46.3 If one of the projects in Tenders D or F was used as part of the Tier 2 portfolio assessed in the Cost-Effectiveness study in Appendix J, please identify which one.
- 46.4 Further to BCUC IR 14.0 in Re-Issued BCUC Information Request No. 1, please repeat questions 14.3 and 14.4 for a Tier 2 scenario that consists only of the biomass project (Tender C).
- 46.5 If the response to the foregoing question contains confidential information, please also provide the total present value result and as much other summary information as possible, in a form that can be provided to all participants.
- 46.6 In the event the responses to BCUC IR 14.3 and 14.4 contains confidential information, please provide the present values and as much other summary information as possible for each scenario to all participants.
- 46.7 If BCUC IR 29.2 results in a refiled form of Attachment A of Appendix J for the situation where the 230 kV AC cables are assumed to be in service for October 2008, please provide the

corresponding spreadsheets (similar to those requested in BCUC IR 14.4) for each CFT outcome and sensitivity analysis for this assumed in-service date.

47.0 Reference: Exhibit A-5, BCUC IR 23.0

- 47.1 Please provide an estimate of the annual cost to BC Hydro of the TGVI service to move gas to Duke Point Power, in then-current and real dollars and the total present value for the study period.
- 47.2 If a completed TSA with TGVI is not available, please outline the current state of negotiations with TGVI, identifying and discussing all material areas of disagreement that remain outstanding.
- 47.3 Please describe each of the fee-setting mechanisms that remain under discussion with TGVI, and discuss the advantages and disadvantages of each.
- 47.4 For each of the fee-setting mechanisms described in the response to the foregoing question, please identify the annual cost to BC Hydro of transporting gas to Duke Point Power, in then-current and real dollars and the present value over the study period.
- 47.5 Will TGVI need to undertake a major expansion of its system to provide firm transportation service to both Duke Point Power and ICP? If BC Hydro believes that a major TGVI expansion will not be required, please explain. In the explanation, please include a discussion of why BC Hydro agreed to fund the capital cost of the TGVI compressor on Texada Island to deliver gas supply to ICP.
- 47.6 If a major TGVI expansion is needed to provide firm service to Duke Point Power and ICP for winter 2007/08, in the opinion of BC Hydro when will TGVI need to decide to go ahead with such an expansion?
- 47.7 Can BC Hydro confirm that any TGVI TSA will need to be approved by the Commission?
- 47.8 Is BC Hydro aware that TGVI has stated that it will not proceed with a major expansion of its system without a long term firm commitment from customers?
- 47.9 In the absence of a firm long term TSA with TGVI, how does BC Hydro intend to provide firm gas supply to Duke Point Power and ICP for the winter of 2007/08? Please provide completed contracts with all parties that are involved in the supply and delivery of such gas for Duke Point Power and ICP.
- 47.10 Further to the foregoing question, please provide the annual cost to BC Hydro of such alternative gas supply and its delivery to Duke Point Power, in then-current and real dollars and the present value over the study period. If more than one alternative gas supply is described, please provide the costs for each of them.
- 47.11 If BC Hydro is unable to provide completed contracts for the firm delivery of gas to Duke Point Power for 2007/08, does BC Hydro believe that the Commission can and should find that the EPA, as a capacity resource, is in the public interest? If yes, please explain your response fully.
- 47.12 Further to the response to the foregoing question, if BC Hydro is unable to file a long term firm TSA with TGVI, please discuss whether the situation is any different with respect to the value of the EPA as a capacity resource for winter 2008/09.

48.0 Reference: Exhibit B-1, Report on the CFT Process

- 48.1 Preamble: Tab A Schedule A Item 1.2: Point 5 of this item indicates that the “contract terms and conditions will be generally consistent with commercial and legal terms and conditions in long-term supply arrangements used by other utilities in procuring electrical capacity and energy, recognizing however the critical nature and timing of the need for new Vancouver Island supply.” Did BC Hydro survey contract terms and conditions for IPP contracts with utilities to develop its own model contract.
- 48.2 Please file the study showing the comparison of terms and conditions, identifying the contracts used (size, fuel type, type of off-taker, criticality of service, type (peaking, base load), contract date, etc.
- 48.3 Please file all contracts that were used as models to design the EPA, and file the Island Cogeneration Project (“ICP”) EPA. For these contracts:
- 48.3.1 How many were for (a) wind, (b) biomass, (c) hydro, (d) gas or oil fired power, and (e) other?
- 48.3.2 How many had a term of 25-35 years, counting initial term and Buyer unilateral right to extend?
- 48.3.3 Please file a long term (10 year plus) Powerex contract for each of a renewable energy project and for an oil or gas power project.
- 48.4 Please compare, preferably in table form, the EPA vs. each of the model contracts and the ICP EPA, as to terms and conditions, including quantitative values, regarding:
- 48.4.1 Term and term renewal rights (EPA Articles 2.1, 2.2).
- 48.4.2 All financial security and LD requirements (type, purpose, magnitude per MW, and whether per MW number is based on dependable capacity or total capacity). Please ensure all items in EPA Articles 13 and 14 are included.
- 48.4.3 Seller’s rights to accelerate COD (EPA Article 5.5).
- 48.4.4 Levels at which penalties or LDs apply for reductions in nominal capacity, availability, level of forced outages, and the type and magnitude of penalties.
- 48.4.5 Contractual right and conditions for Seller selling excess capacity/energy to third parties (EPA Article 8.6).
- 48.4.6 Damage or Destruction of Seller’s Plant (EPA Article 11.3).
- 48.4.7 Force Majeure or other provisions offering Seller relief or contract termination in the event of Seller’s inability to obtain or maintain permits.
- 48.4.8 Step In Rights (EPA Article 16).

- 48.4.9 Payment on Termination (EPA Articles 17.4, 17.5).
- 48.4.10 Payment for energy and capacity during commissioning, testing, and pre-COD (EPA Article 8 and Appendix 3).
- 48.4.11 Change in law provisions (apparently not in EPA).
- 48.4.12 Payment for fuel during testing, commissioning, and other pre-COD activities.
- 48.5 Where the stringency of the EPA financial assurances or LDs exceeds those of the ICP EPA or other model contracts, please justify the need for the increased stringency. Please state specifically how LD levels and financial assurance levels were set.
- 48.6 Given the magnitude and number of financial assurances contained in the EPA, why was a subordinated mortgage required?
- 48.6.1 Please explain how the subordinated mortgage provisions work, how they would protect Buyer, and the risks to Seller.
- 48.7 Please provide examples from the ICP and the model contracts where a development security, an operating security, capacity shortfall security, step-in rights, and a subordinated mortgage were all required of Seller. Please list the amounts per MW for each security.
- 48.8 Tab B, page 12, and Tab G page 1: Why did BC Hydro in Addendum 10 change the required term of the EPA from 10-25 years, to minimum 25 years with a unilateral BC Hydro option for 35 years. (Note: Ex. B-1, Tab A, CFT documents, Background, Schedule A, item 2.2, call for “20 years’ supply”).
- 48.9 Have terms shorter than the 25-35 years of this EPA been allowed for biomass and other “renewable sources” in the model contracts, contracts by other Canadian crown power companies, or by Powerex or BC Hydro where new or expanded facilities are involved? For oil and gas projects including ICP, please also address. Please identify the contracts and term.
- 48.10 What is BC Hydro’s estimate of the cost to BC Hydro and hence its ratepayers of each of the contract requirements in the EPA to the extent they are more stringent than the ICP or typical industry contracts, given that bidders presumably price these requirements into the EPA pricing.
- 48.11 What steps did BC Hydro take, through negotiation with bidders, or studies, to determine the value of incremental/decremental strengthening of each of these provisions so as to determine if it was more appropriate from a ratepayer cost perspective to adjust the provisions?

49.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 2.1 Term and Renewal Rights

- 49.1 Assuming such bids met pricing, reliability, and availability objectives, why can BC Hydro not accept contracts of shorter terms than the 25-35 years specified in the EPA, such as 10-15 years, or (for example) 7 year, annually renewed ever-green contracts that leave sufficient time to replace an expiring contract if the Seller does not renew 7 years before expiry?

- 49.2 Does the contract term of 25 years, with a unilateral right to renew for up to 10 years, eliminate commercially, most or all biomass and captive power facilities from the effective competition as they cannot make such long commitments. If BC Hydro feels otherwise, please provide the rationale and support.
- 49.3 Has BC Hydro researched the issue to determine if it is possible for biomass projects to achieve 25-35 year fuel supply commitments, and for “captive” power plants at industrial facilities to make such long term commitments to supply power to BC Hydro? Please provide any such studies. If not, why not since BC Hydro had specifically committed to attempt to accommodate the widest possible range of supply technologies and options (Exhibit B-1, Tab A, Appendix A, page 39).

50.0 Reference: Exhibit B-1, Tab N, EPA Filing, Unilateral Rights and One-Sided Requirements

- 50.1 Please explain why BC Hydro requires unilateral rights in the following articles of the EPA. For each individual example cited, why is it not possible to give the same right to both parties, or require mutual agreement where a decision is to be made?
- 50.1.1 Article 2.2: Buyer can unilaterally extend the term of the EPA..
- 50.1.2 Article 2.3: Upon notice to arbitrate, Buyer can withdraw the Renewal Notice.
- 50.1.3 Article 22.7: In arbitration, Buyer is specifically allowed to take certain court actions.
- 50.1.4 Article 4.5: Why is Seller required to keep Buyer up-to-date on project development status, but Buyer is not required to keep Seller up-to-date on status of Buyer’s permitting, regulatory initiatives, gas supply arrangements, load forecasts, etc. that affect the project?
- 50.2 Does BC Hydro agree that unilateral or one-sided clauses are likely to make the EPA less attractive to bidders and/or more expensive to BC Hydro ratepayers as bidders price in such terms? If not, why not?
- 50.3 Are EPA renewal rights typically unilateral in favour of Buyer, based on the model contracts and the ICP contract? If yes, please demonstrate.

51.0 Reference: Exhibit B-1, Tab N, EPA Filing, Cost of EPA and CFT Requirements

- 51.1 What is BC Hydro’s estimate of the cost to BC Hydro and hence its ratepayers of each of the following contract requirements in the EPA, due to bidders presumably having priced these requirements into the EPA pricing:
- 51.1.1 The unilateral rights in item 3.0 above, vs. the case where bilateral rights or mutual consent had been allowed?
- 51.1.2 Seller’s inability to, in effect, earn a larger bonus for early completion (EPA 5.5) given BC Hydro’s right to deny acceleration of COD by more than 30 days. In view of the capacity supply/demand situation, why is this COD acceleration restricted to 30 days?

51.1.3 Retention of Green Rights and Off Site Emission Reduction rights (EPA 8.10).

51.1.4 Step In Rights (Article 16).

51.1.5 The subordinated mortgage (Article 14.8).

51.2 What steps did BC Hydro take, though studies or interaction with bidders, to place a value on each of these provisions so as to determine if it was more appropriate from a ratepayer cost perspective to grant the benefit to Seller or to “level” or eliminate the provision, as the case may be?

52.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 3.2, EPA Support

52.1 Please confirm the payment for breach of this clause would be in the order of \$30 MM for the DPPLP facility. What is the justification to have so high a payment for this clause? Please provide examples of this clause with such large payments in other Canadian crown utility IPP contracts or other BC Hydro contracts with IPPs.

52.2 Why, unlike Article 22.8(d) of the EPA, is there no provision to require only commercially reasonable efforts and to provide evidence and argument only as “reasonably necessary?”

52.3 The penalty for breach is very serious and the standards for a breach are not defined. Please provide BC Hydro’s views as to what acts, or failures to act, could constitute a breach.

52.4 Is BC Hydro not concerned that these provisions could affect the ability of Seller or Buyer to be completely candid in regulatory proceedings, and if not, why not?

52.5 Has BC Hydro found similar provisions in the model contracts? If so, please file the provisions and identify the contracts, including the quantum of the potential liability.

53.0 Reference: Exhibit B-1, Tab N, EPA Filing, Articles 4.6, 4.7, 6.2, 6.9 Buyer Role in Construction and Operations

53.1 Given the financial security and LDs together with Seller’s contractual obligations, why does Buyer need to be involved to such an extent in monitoring and reports (Articles 4.6, 4.7, 6.9) on the construction and operations of the plant including the operating committee?

53.2 Article 6.2: Seller is required to notify Buyer of every modification to the plant even if “not likely to have an adverse effect on the Seller’s ability to observe and perform its obligations?” Given that there is no materiality standard in this clause, this could be hundreds of items a month requiring reporting. Why does Buyer need or even want this?

53.3 Is Article 6.2 a requirement of the ICP contract, and if not, why is it required in this EPA?

54.0 Reference: Exhibit B-1, Tab N, EPA Filing, Articles 6.7 Demonstration Tests

54.1 Why are demonstration tests required quarterly rather than annually?

54.2 Is quarterly testing a requirement of the ICP contract or any or all of the gas fired model contracts, and if not, why is it required in this EPA? Please advise how many of those contracts require (a) quarterly and (b) annual testing.

54.3 How often does ICP require testing?

55.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 8.8, Limitations of Delivery and Acceptance Obligations

55.1 Sub clause (vi) provides consequences if forced outages cause A_{monthly} to drop below 97%. Please provide the annual average A_{monthly} for the last five years for each of BC Hydro's generation plants including ICP, and equivalent for the main transmission lines, and justify the 97% requirement.

55.2 In BC Hydro's understanding, can each of biomass, wood, wind, and small run-of-river hydro typically be expected to meet this 97% standard?

55.3 Is the 97% standard applied only in the peak season, and if so, explain where and how this is covered in the contract.

55.4 Explain all consequences, referencing clause numbers, of Seller's failure to meet the 97% standard in the EPA pre and post COD.

56.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 8 Emission reduction Rights and Green Rights

56.1 What is the justification for BC Hydro retaining the Off Site Emission Reduction Rights and the Green Rights, as opposed to allowing them to accrue to Seller? What are they worth financially or strategically?

56.2 Is this a reasonable and balanced approach given that Seller appears liable for any cost increases due to changes in environmental laws?

57.0 Reference: Exhibit B-1, Tab N, EPA filing, Article 11.3, Damage or Destruction of Seller's Plant

57.1 Please explain the rationale of requiring Seller to replace the plant if the event occurred close to the end of the Term of the EPA. It appears the Seller could be compelled by the EPA to spend large sums of money, whether insurance funds or otherwise, and potentially have the EPA terminated shortly thereafter at end of term. Is this commercially reasonable, and if so, why?

57.2 Why is this obligation not tempered by a standard of commercial reasonableness, or at a predefined severe level of damage, by an option for Seller to terminate with a termination payment?

57.3 Please rationalize the different approach to this issue applicable after the primary term of the agreement (Appendix 16, clause 11.3, last two sentences). Why is it more critical for Buyer to be able to unilaterally force rebuilding of the plant, (where it takes more than 180 days) in year 10 or 20, for example, vs. year 26 plus?

57.4 Please rationalize this Article 11.3 approach vs. the ICP EPA and the model contracts.

58.0 Reference: Exhibit B-1, Tab N, EPA Filing, and Exhibit B-4 Article 12, Force Majeure

58.1 Although Article 12 specifies that economic hardship or lack of money is not a valid cause for invoking Force Majeure, the normal statement that obligations to pay monies are not excused by a Force Majeure declaration appears to be missing in the EPA. Why?

58.2 Please confirm that the inability of Seller to obtain or maintain permits is not an event of Force Majeure, except in very limited circumstances (EPA Appendix 1, definition 49 and EPA Article 12), and please describe those circumstances. What relief has Seller if it cannot, despite best efforts, maintain or renew permits?

58.3 **REDACTED** Please confirm

58.4 What advantage would a Seller receive by electing the option of Appendix 17, Part N? Even if Seller had such permits at contract execution, what incentive is there for Seller to allow elimination of Article 17.2 (b) and lose its (albeit temporary) protection due to a possible glitch in an awarded permit.

58.5 **REDACTED** Given that BC Hydro

58.6 **REDACTED** What cost does BC

58.7 Why is BC Hydro's inability to supply gas due to a failure of firm upstream transportation not an event of Force Majeure? Please contrast this with the Force Majeure provisions of the ICP Electricity Purchase Agreement, and explain the rationale for any differences.

58.8 If BC Hydro is relying on Appendix 15 regarding failure of its gas supply arrangements, please address the following:

58.8.1 **REDACTED** Please confirm

58.8.2 Please advise of the intent of clause 12, Part B, Appendix 15, wherein it appears Buyer can declare Force Majeure if "gas is not available at Huntington." Is the intent that gas is not generally available, or is not available only to Buyer? What are the implications if gas is not available to Buyer due to Buyer's failure to contract for it, or failure of Buyer's suppliers to deliver?

59.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 17.5, Payment on Termination

59.1 Please provide an illustrative calculation of the payment for termination by Seller post COD.

59.2 Please clearly describe the intent of the Article 17.5 (b). Is the intent to pay Seller its lost future NPV after termination?

60.0 Reference: Exhibit B-1, Tab N, EPA Filing, Article 8.6 Exclusivity (Third Party Sales)

- 60.1 Why is sale of energy or capacity to a third party in violation of the EPA so serious as to be classified as a Deliberate Breach [Appendix 1, definition 28 (d)], without an exclusion for a case where it might occur by misunderstanding or error or the case where BC Hydro had no need of energy or capacity and suffered no harm? What apparent serious harm does BC Hydro contemplate from such an event, given Seller's obligations under the EPA?
- 60.2 Why is the sale of capacity or energy to third parties so restrictive (only over 105% Nominal Capacity, several notices, requirement to offer to reset Nominal Capacity in some cases with 30 day wait period, etc.), even for cases where Buyer may have no need of energy or capacity?
- 60.3 If Seller requires Buyer consent for every sale under Article 8.6(c)(ii), how would spot market sales such as to Powerex or third parties be addressed, given the required procedures and notices including Buyer, in some cases, having the right to 30 days to consider Offered Capacity?
- 60.4 Under Article 8.6(c), what proof would Buyer expect that the plant can operate at above 105% of Nominal Capacity, and how recent would that proof have to be?
- 60.5 If it were summer and Buyer had no need of much capacity or energy from the plant, why would Buyer object to third party sales even if Seller temporarily could not operate above 105% of Nominal Capacity? Why does the contract prohibit this?
- 60.6 Please explain the intent and working of Part A 3, Appendix 15, in this scenario. The plant is operating at 50% of Nominal Capacity because Buyer has little demand. Seller has an opportunity for a third party sale. Does this scenario not result in a failure of the Metered Energy "test", prohibiting the Seller from making third party sales just when capacity is available to do so?
- 60.7 Please indicate which, if any, of the model contracts and ICP take the same approach, and rationalize the treatment, if different.
- 60.8 Why could Seller not be specifically permitted, at any time when capacity surplus to Buyer's needs is available, to sell such excess capacity or energy, perhaps in an arrangement to provide financial benefits to both Seller and Buyer, and absent Buyer's consent for each sale where no injury to Buyer could reasonably be foreseen?
- 60.9 Renewable projects tend to have less certain dependable capacity, and therefore to meet the 97% availability requirement, may "lowball" their declared Nominal Capacity and try to offset the lower capacity payments with energy sales. However, EPA 8.6 appears to act in the opposite direction by handicapping third party sales. Does this EPA approach not in BC Hydro's opinion discourage renewables, and if not, why not?

61.0 Reference: Exhibit B-1, Tab N, EPA Filing, Articles 13.6 and 14.5, Limited Liability and Replenishment

- 61.1 Please indicate in what circumstances and under what EPA articles Seller has unlimited liability, taking into account the replenishment provisions of Article 14.5, the exceptions in Article 13.6, and such other articles as may impose or limit liabilities on Seller.
- 61.2 Would BC Hydro agree that if a Seller is exposed to unduly high or unlimited liabilities, it may render a project unfinanceable, forcing bidders withdrawal, and/or may increase the bid prices to Buyer? If not, why not?
- 61.3 IPP projects generally pass through construction and pre-COD LD risk “back to back” to the EPC contractor. Would BC Hydro agree that unlimited or excessive liabilities or LDs would tend to increase costs charged by the EPC Contractor? If not, why not?
- 61.4 Please compare the model contracts and ICP EPA to this EPA in terms of limits on liability.
- 61.5 Why could not BC Hydro provide an overall liability cap, even if at a high level equivalent to, say, the cost of the plant?
- 61.6 In view of its “step-in” rights under the EPA Article 16, why is unlimited liability required, particularly given the significant securities, LDs, the subordinate mortgage, and the replenishment provisions?
- 61.7 What is BC Hydro’s approximate financial exposure if the plant failed completely and permanently and it took the same period of time as DPPLP to build a replacement plant?
- 61.8 How many parties involved in the CFT indicated that unlimited liability was a serious issue? How many of these parties declined to bid? How many named this issue as a reason to decline bidding? How many of those who declined are corporations with over \$500 MM in assets?

62.0 Reference: Exhibit B-4, DPPLP EPA Appendix 5, Duct Firing and Capacity Degradation

- 62.1 What is the approximate MW output, if any, available from duct firing?
- 62.2 Has BC Hydro included this capability, if any, in the contracted capacity? If not, why not?
- 62.3 Is the stated value for Capacity Degradation in the DPPLP EPA reasonable and proven, and on what basis?

63.0 Reference: Exhibit B-1, Tab N, EPA Filing, Appendix 16 EPA Terms and Conditions for Renewal Terms

- 63.1 Clause 7 of Appendix 16 seems to imply that responsibility for fuel procurement has shifted from Buyer (Appendix 15, Part B, clause 2) to Seller in Renewal Terms. Is this correct, and if so why has the role shifted and where is this shift provided for in the EPA? If not, what is the purpose of clause 7?
- 63.2 In view of the importance that BC Hydro appears to place on financial security, why are the LDs in clause 9 not escalated for inflation given the 25 year lapse?

64.0 Reference: Exhibit B-4 DPPLP EPA Filing, Appendix 5, Dual Fuel Operation

64.1 REDACTED The

64.2 REDACTED Please confirm

64.3 Please advise of the dual fuel scenarios that were studied by Seller or BC Hydro and the net cost advantage or disadvantage in the dual fuel scenario.

65.0 Reference: Exhibit B-1, Tab N, EPA Filing, Apparent Lack of Change in Law Provision

65.1 Does BC Hydro believe that any EPA provisions afford the Seller relief from changes in law (“CIL”) post EPA execution, such as changes in taxes, fees, levies, duties, health and safety or environmental regulations, green house gas or carbon taxes, etc. imposed by governmental authorities? If so, please identify the provisions. Please confirm that CIL is not a Force Majeure event.

65.2 Under VIGP, BC Hydro would incur some or all of the CIL risks, and arguably, BC Hydro has a greater ability than an IPP company to mitigate at least British Columbia CIL. Please rationalize why the EPA does not contain a CIL provisions to apportion some CIL risks to BC Hydro, particularly given the 25-35 year contract.

65.3 What cost does BC Hydro anticipate bidders priced into their bids for CIL risk being apportioned (apparently entirely) to Seller for 25-35 years?

65.4 Does BC Hydro see it as reasonable and balanced to take the Green Rights while leaving all project environmental CIL to Seller?

65.5 How many parties involved in the CFT indicated that lack of CIL coverage in the EPA was a serious issue? How many of these parties declined to bid? How many named lack of CIL protection a factor in declining to bid? How many of those who declined are corporations with over \$500 MM in assets?

66.0 Reference: Exhibit B-1, Tab N, EPA Filing, GSX Issues

66.1 Please describe any potential liabilities to BC Hydro or its affiliates and subsidiaries (“BCH Family”), under any circumstances, in the event the GSX pipeline project terminates.

66.1.1 What is the status of the GSX project and the agreements between its proponents and the BCH Family? From BC Hydro’s perspective, is the project still an option for supplying the DPPLP plant?

66.1.2 Please file the contracts(s) between BCH Family and Williams or other involved parties.

66.1.3 Do any of the BCH Family contracts with Williams or other GSX parties contain a clause of like effect to Article 3.2 of the EPA, and if so, what would be the amount potentially payable by BCH Family?

67.0 Reference: Exhibit B-1, Tab N, EPA Filing, Exhibit B-1, Tab N and Exhibit B-4

67.1.1 Please file in confidence with the BCUC, a mark-up of the generic EPA showing all differences between the DPPLP and the EPA.

68.0 Reference: Exhibit B-1, Tab N, EPA Filing, Miscellaneous

68.1 Why is the typical “improper draw” clause in favour of Seller regarding letters of credit draws not included?

68.2 Please identify legislation, acts, regulations, or agreements that impose on Terasen a legal obligation to serve the DPPLP plant with gas transportation services.

68.2.1 What arrangements and action on the part of Terasen and BC Hydro are required to obtain such service? What is the status of the arrangements? Are negotiations for service underway? When is completion anticipated?

68.2.2 What risks does BC Hydro run in committing to DPPLP via its EPA and other agreements without (apparently) formal arrangements with gas transporters and suppliers? If BC Hydro sees no risk, please explain why.

68.2.3 Please file all communications between Terasen and BC Hydro relating to the negotiations for transportation service. Pricing or other confidential information may be redacted.

68.2.4 What is BC Hydro’s fallback plan if, for whatever reason, gas or gas transportations service is not available at the plant in time for commissioning, testing, and COD?

69.0 Reference: Report on CFT Process, Exhibit B-1, Background

69.1 Page: 6: How many parties in the CFT process at April 30 2004 dropped out in March 2004 after the March 5 issuance of Addendum 10? Please identify the parties. Did any cite Addendum 10 as the reason, and if so, what, if any, specific provisions did they cite? Please file any relevant correspondence from bidders as to their reasons for dropping out of the process.

69.2 Page 8: Please file, in confidence with the BCUC if necessary, both BC Hydro’s written recommendations and reports with the full reasons for disqualifying the three bidders mentioned in section 2.6, and the INRV’s written confirmation of same. Please clearly indicate the mandatory criteria each bidder failed to meet, the evidence to that effect, and file the bidders’ responses to the disqualification, if any. Please also file the reports of any third party experts involved in the evaluations leading to the disqualifications.

69.3 Page 8: Section 2.6, paragraph 2, indicates 3 bidders were disqualified from 11, presumably leaving 8 pre-qualified bidders. The first paragraph of section 2.7 mentions 9 pre-qualified bidders submitted proposals at a later date. Please explain.

- 69.4 Page 8: Please file, in confidence with the BCUC if necessary, both BC Hydro's written recommendations and reports with the full reasons for disqualifying the three bidders mentioned in section 2.7, and the INRV's written confirmation of the fairness of the disqualifications. Please clearly indicate the "non-compliance" in detail, the evidence to that effect, and bidders' responses, if any. For the bidder disqualified due to "material conditions," please file a copy of those conditions, with the reasons BC Hydro feels they are material.
- 69.5 Has BC Hydro conducted any post mortem to determine why of 23 registered parties, only 11 pre-qualified as of April 29, and of that number, only 4 were not disqualified from tendering?
- 69.6 Page 9: Please indicate the type and location of each of the 6 evaluated projects, and indicate if they are VIGP type projects.
- 69.7 Page 18: Please explain whether or not for emergency backup for Vancouver Island, BC Hydro expects to obtain the necessary permits for backup generation assuming the backup generation is operated only when necessary to "keep the lights on" on Vancouver Island?
- 69.8 Page 24 section 9: BC Hydro states that "a competitive process should produce a cost effective outcome," and that the BCUC should focus on competitiveness, not the outcome.
- 69.8.1 If a CFT process, including the EPA, imposed on bidders unduly harsh terms and conditions not typical of industry practice, or not commercially reasonable, and not required to attain the reliability and other requirements of Buyer, would that not directionally induce bidders to quit the process, or increase bid prices, compared to "normal" terms and conditions? If not, why not?
- 69.8.2 If such a scenario were to occur, would this not indicate that the process, although competitive, would not produce the lowest practical price or most "cost effective outcome" compared to a case where terms and conditions, while still appropriate, were less stringent?

70.0 Reference: Report on CFT Process , Exhibit B-1, Background, Tab A

- 70.1 Appendix A, Sch. A, Page 42: Please provide the documentation supporting the mandatory criteria regarding the successful bidder, in confidence with the BCUC if necessary. Please indicate the arrangement and the personnel for commissioning, startup, and operations. What parties have partnered with Bidder to ensure the criteria are met, and what are their qualifications?
- 70.2 Appendix A, Sch. A, Page 43: Please rationalize the mandatory requirement that any conditions relative to permits in the tender be satisfied before a contract will be signed, vs. industry practice, and vs. the draft Exhibit B-1, Tab N, EPA Article 17.2(b). Was this required of ICG or any of the model contracts?
- 70.3 Appendix A, Sch. A, page 44: In the early stages of the process, the proposed INRV role provided for communication between bidders and the INRV in the workshops. Did such contact occur, and if not, why not?
- 70.3.1 If such contact was prohibited between bidders and INRV at any time, who issued the prohibition and what was the rationale?

70.3.2 Were bidders restricted from communicating with any other parties? Please provide a complete list of the parties to whom they were not permitted to communicate, with the rationale.

71.0 Reference: Report on CFT Process , Exhibit B-1, Tab B, Appendix 9, INRV, Role

71.1 Why was the INRV not required to examine the terms and conditions of the CFT contracts, and particularly the EPA vs. the model contracts and perhaps the ICG EPA, to determine if they were reasonable vs. typical industry standards as adjusted for this project, and to ensure they were not biased towards a VIGP solution? Was this considered at any stage, either verbally or in writing?

71.1.1 Alternatively, why did BC Hydro not have the INRV review BC Hydro's work that set the terms and conditions to ensure they were reasonable and not likely to discourage competition unduly?

71.1.2 Please file all versions of the terms of reference for the INRV, and the RFP issued to those who bid on the INRV job.

71.1.3 Please file all responding tenders to the RFP. Pricing may be deleted.

72.0 Reference: BCUC IR#1, Question 9.0, Evaluation Model Files(Provided Confidentially by BC Hydro December 1, 2004)

72.1 Please provide summary tables comparing key inputs and outputs for each tender project as outlined below. One table should show results under the EIA-partial electricity forecast and another under the EIA-full electricity forecast. For the second table, only fill in the tender identification and any cells where values change as a result of using a different electricity price forecast. For items that are not applicable to a particular project, please indicate N/A. Please provide notes to the tables if BC Hydro wishes to provide additional explanation for any values. Please include information for all ten (10) of the projects originally tendered in the CFT process, including the three (3) projects that were rejected for non-compliance with the CFT requirements, as well as the VIGP benchmark using the same input assumptions as other bids (e.g., updated gas price forecast). Please indicate which tenders were rejected in row 4 of the table.

72.2 Please specify what assumption is made on GHG liability in the VIGP benchmark and the effect this assumption has on the levelized cost of dispatch in Row 54 of the table below.

72.3 Please reproduce the table below under the following alternative assumptions. For each sensitivity, only fill in the tender identification and any cells where values change as a result of using a different electricity price forecast.

72.3.1 Gas price forecast

72.3.1.1 Reproduce the EIA – partial and EIA- full tables under comparable EIA high gas forecast (January 2004) instead of the Reference Case.

72.3.1.2 Reproduce the EIA – partial and EIA- full tables under comparable EIA low gas forecast (January 2004) instead of the Reference Case.

72.3.2 Discount rate sensitivity

72.3.2.1 Reproduce the EIA – partial and EIA- full tables from Question 72.1 using 6% and 10% nominal discount rates.

72.3.3 Exchange rate sensitivity

72.3.3.1 Reproduce the EIA – partial and EIA full tables from Question 72.1 using exchange rate forecasts that are a) 10% higher and b) 10% lower than the base exchange rate forecast.

72.4 Please confirm that the net tender costs in the tables produced for Question 72.1 above include interconnection costs for projects (as part of the capital charges bid by proponents) but do not include any salvage value for VIGP assets, gas transportation costs or network effects. Please confirm these latter impacts are dealt with in the portfolio-level evaluation.

Tender comparisons under XXXX electricity forecast

		Tender Project A	Tender Project B	Etc...
1	Tender Identification (as used by BC Hydro)			
2	Bidder name			
3	Plant location			
4	Accepted or rejected			
5	Dispatch rights (per BC Hydro classification in Section 4.2 of Appendix H of Application)			
6	Fuel (if dual fuel, indicate primary and secondary fuel)			
7	Fuel pricing (indicate if fixed, variable or mixed as in the case of full or partial tolling plants)			
8	Bid capacity (MW)			
9	Minimum turndown (%)			
10	EPA initial term (years)			
11	Avg Degraded Capacity at AAC (MW)			
12	Firm gas transportation requirements (TJ/day)			
13	Non-firm gas transportation (TJ/day)			

1 4	Baseload heat rate (GJ/GW.h)			
1 5	Minimum turndown heat rate (GJ/GW.h)			
1 6	Heat rate degradation factor over initial term			
1 7	Variable (non-fuel) O&M charge (\$/MW.h)			
1 8	Escalation rate on variable (non-fuel) O&M charge			
1 9	Scheduled planned outage allowance in major maintenance years (hours / year)			
2 0	Scheduled planned outage allowance in non-major maintenance years (hours / year)			
2 1	Major maintenance interval (in fixed frequency OR Equivalent Operating Hours)			
2 2	Expected operating hours (OH) in start-up mode			
2 3	Total (sum of annual OH in start-up mode)			
2 4	NPV (NPV of annual OH in start-up mode)			
2 5	Expected operating hours per year at less than full output, if applicable			
2 6	Total (sum of annual OH at less than full output)			
2 7	NPV (NPV of annual OH at less than full output)			
2 8	Expected operating hours per year at full output			
2 9	Total (sum of annual OH at full output)			
3 0	NPV (NPV of annual OH at full output)			
3 1	Expected total equivalent operating hours (EOH)			
3 2	Total (sum of annual EOH)			
3 3	NPV (NPV of annual EOH)			
3 4	Dispatch – must run (MWh)			
3 5	Total (sum of annual must-run dispatch over life of plant)			

3 6	NPV (NPV of annual must-run dispatch over life of plant)			
3 7	Dispatch – reliability (MW.h)			
3 8	Total (sum of annual dispatch at BCH discretion for reliability reasons, if not must run plant or if reliability requirement exceeds must-run dispatch)			
3 9	NPV (NPV of annual dispatch for reliability reasons)			
4 0	Dispatch – economic (MW.h)			
4 1	Total (sum of annual expected plant dispatch in excess of must run and/or reliability requirements based on gas and electricity opportunity costs)			
4 2	NPV (NPV of annual economic dispatch)			
4 3	Total dispatch (MWh)			
4 4	Total (sum of annual must-run, reliability and economic dispatch)			
4 5	NPV (NPV of annual must-run, reliability and economic dispatch)			
4 6	Capacity Factor over initial Term (%)			
4 7	Capacity charges NPV (\$000)			
4 8	Fixed O&M charges NPV (\$000)			
4 9	Capacity and Fixed O&M charges NPV (\$000)			
5 0	Variable dispatch costs NPV (\$000)			
5 1	Fuel			
5 2	Non-fuel			
5 3	Total			
5 4	Levelized cost of dispatch (\$/MW.h) [Row 53 divided by Row 45]			

55	Market value of energy NPV (\$000)			
56	Levelized value of energy (\$/MW.h) [Row 55 divided by Row 45]			
57	Energy margin NPV (\$000) [Row 55 minus row 53]			
58	Startup cost NPV (\$000)			
59	Net Tender Cost NPV (\$000) [Row 49 minus Row 57 plus Row 58]			
60	Levelized capacity cost before credit for energy margin (\$/MW) [Row 49 divided by Row 11]			
61	Levelized capacity cost after credit for energy margin (\$/MW) [Row 59 divided by Row 11]			

73.0 Reference: BCUC IR#1, Question 14.0,

73.1 Further to the Commission's IRs regarding the evaluation of the three CFT outcomes discussed in Appendix J, please provide two summary tables as illustrated below comparing inputs and outputs for all possible Tier 1 (including VIGP benchmark) and Tier 2 portfolios under EIA-partial and EIA - full electricity forecasts, based on tender costs in preceding IR.

73.2 Please reproduce the table below under the following alternative assumptions. For each sensitivity, only fill in the tender identification and any cells where values change as a result of using a different electricity price forecast.

73.2.1 Gas price forecast

73.2.1.1 Reproduce the EIA – partial and EIA- full tables under comparable EIA high gas forecast (January 2004) instead of the Reference Case.

73.2.1.2 Reproduce the EIA – partial and EIA- full tables under comparable EIA low gas forecast (January 2004) instead of the Reference Case.

73.2.2 Discount rate sensitivity

73.2.2.1 Reproduce the EIA – partial and EIA- full tables from Question 73.1 using 6% and 10% nominal discount rates.

73.2.3 Exchange rate sensitivity

73.2.3.1 Reproduce the EIA – partial and EIA full tables from Question 73.1 using exchange rate forecasts that are a) 10% higher and b) 10% lower than the base exchange rate forecast.

		Tier 1 - Portfolio A	Tier 1 - Portfolio B...etc.	Tier 2 – Portfolio A	Tier 2 – Portfolio B...etc.
1	Portfolio composition and capacity of each individual project				
2	Total portfolio bid capacity (MW)				
3	Average portfolio degraded capacity (MW)				
4	Firm gas demand (TJ/day)				
5	Interruptible gas demand (TJ/day)				
6	Portfolio dispatch – must run (MW.h)				
7	Total (sum of annual must-run dispatch)				
8	NPV (NPV of annual must-run dispatch)				
9	Portfolio dispatch – reliability (MW.h)				
10	Total (sum of annual reliability dispatch, if applicable)				
11	NPV (NPV of annual reliability dispatch, if applicable)				
12	Portfolio dispatch – economic (MW.h)				
13	Total (sum of annual economic dispatch – i.e., dispatch that is not must run or for reliability reasons but rather based on gas and electricity prices)				
14	NPV (NPV of annual economic dispatch)				
15	Portfolio dispatch – total (MW.h)				
16	Total (sum of annual must-run, reliability and economic dispatch)				

1 7	NPV (NPV of annual must-run, reliability and economic dispatch)				
1 8	Portfolio capacity charges NPV (\$000)				
1 9	Portfolio fixed O&M charges NPV (\$000)				
2 0	Portfolio variable dispatch costs NPV (\$000)				
2 1	Fuel				
2 2	Non-fuel				
2 3	Total				
2 4	Levelized cost of portfolio dispatch (\$/MW.h) [Row 23 divided by Row 17]				
2 5	Market value of portfolio energy NPV (\$000)				
2 6	Levelized value of portfolio energy (\$/MW.h) [Row 25 divided by Row 17]				
2 7	Energy margin NPV (\$000) [Row 25 minus row 23]				
2 8	VIGP salvage value adder NPV				
2 9	VIGP asset sale adder NPV				
3 0	Firm gas transportation adder NPV (\$000)				
3 1	Network effects adder NPV (\$000)				
3 2	Start-up cost NPV (\$000)				
3 3	Net tender cost NPV (\$000) [Row 18 plus Row 19 plus Row 32 minus Row 27]				
3 4	Net portfolio cost NPV (\$000) [Row 33 plus Row 28 plus Row 29 plus Row 30 plus Row 31]				
3 5	Levelized portfolio capacity cost before credit for				

	energy margin (\$/MW) [(Row 34 plus Row 27) divided by Row 3]				
3 6	Levelized portfolio capacity cost after credit for energy margin (\$/MW) [Row 34 divided by Row 3]				
3 7	Portfolio capacity factor				

74.0 Reference: Appendix B – Call for Tenders issued on October 31, 2003, Appendix 1 Guaranteed Availability

- 74.1 Are there any WECC or other industry standard guidelines that reference a guaranteed availability of 97% for a generation source to be considered “Dependable Capacity” for planning purposes? If so, please provide these guidelines.
- 74.2 According to WECC or other industry standard guidelines, what is the minimum guaranteed availability that a generation source must achieve in order to be considered as “Dependable Capacity” for planning purposes? What other minimum criteria are necessary according to the guidelines for a generation source to be considered as “Dependable Capacity” for planning purposes?
- 74.3 What are BC Hydro’s minimum criteria for a generation source to be considered as “Dependable Capacity” for planning purposes?
- 74.4 What is the availability of the ICP and what “Dependable Capacity” has it been assigned for planning purposes? Is there a relationship between availability and “Dependable Capacity” for this plant, and if not at its maximum possible “Dependable Capacity” rating, what availability would it need to demonstrate to achieve this rating?
- 74.5 What is the lowest availability of any generating facility in BC Hydro’s system that has a “Dependable Capacity” that is at least 50% of its nominal rating?
- 74.6 If the guaranteed availability mandatory criterion in the Call for Tenders was reduced to 90%, how many of the pre-qualified submissions that previously failed that individual criterion would now pass it, and at what capacity value? Please repeat for 80%. If there are any projects that now pass that criterion, please generate the corresponding NPV comparisons, similar to the VIGP benchmark.
- 74.7 Of the 23 registered bidders in November 23, 2003, to BC Hydro’s knowledge, how many of these bidders cited the guaranteed availability criterion as being too onerous for their proposed project?
- 74.8 Please provide industry benchmarks (WECC) for the availability of coal-fired generating stations, and identify the Dependable Capacity as used for planning purposes that is associated with such generating stations.

74.9 What is the guaranteed availability associated with the natural gas supply to the Duke Point Project?

**75.0 Reference: Final Form EPA – Appendix 2
Project Milestone Schedule**

75.1 Please provide the rationale for the length of time between the Synchronization Date and the Commercial Operation Date.

75.2 Please supply the rationale for the length of time between the Commercial Operation Date and the estimated earliest date that the Duke Point Power project's capacity would be required to serve winter peak load?

75.3 In the last 30 years, what is the earliest date that a winter peak demand has been set, and at what percentage of the forecast for that year?

75.4 Is there any premium in the project cost structure for the length of time between the COD and the estimate earliest date by which the capacity would be required?

75.5 What is the length of time necessary to install and bring a TM2500 generator on-line to serve a winter peak load?

75.6 What are the ramifications, costs and risks of delaying all future dates in the Project Milestone Schedule by 90 days?

**76.0 Reference: Final Form EPA
Nominal Capacity and Liquidated Damages Calculation**

76.1 Assuming the Duke Point Power project achieves a May 1, 2007 COD with an AAC Equivalent Capacity equal to the Bid Capacity and maintains that until February 1, 2008, please supply the monthly invoices associated with Capacity Charges, Liquidated Damages and other charges for the period of January 2008 to January 2009 for the following sequence of Demonstration Tests:

Demonstration Test Date	AAC Equivalent Capacity
February 1, 2008	96% of Bid Capacity
May 1, 2008	93% of Bid Capacity
May 3, 2008	92% of Bid Capacity
August 1, 2008	91% of Bid Capacity
August 5, 2008	89% of Bid Capacity
November 1, 2008	96% of Bid Capacity

Please supply all supporting calculations and assumptions for the evaluation of the Capacity Charges, Liquidated Damages and other charges, including the calculation of the Nominal Capacity.

**77.0 Reference: Final Form EPA – Appendix 11
Capacity and Heat Rate Adjustment tables**

77.1 Is operation of the Duke Point Power project possible for the temperature and humidity conditions where no entry appears in the Capacity Conversion Table and the Heat Rate Adjustment Table, and is so, what adjustment factors apply to these ambient conditions?

**78.0 Reference: Executed EPA – Appendix 9
Dispatch Terms and Conditions**

78.1 REDACTED What effect will

78.2 If the number of allowable Cold Starts in an EPA Year have been consumed, does this then mean that the project can not be dispatched off for the remainder of the EPA Year, or if it is, it must come back into dispatch soon enough to qualify as a Warm Start or a Hot Start?

78.3 What are the ramifications of exceeding the number of allowable Cold Starts, Warm Starts or Hot Starts in a given EPA Year?

**79.0 Reference: Executed EPA – Appendix 5
Seller’s Plant Description**

79.1 REDACTED Describe the restrictions that limit the Seller’s ability to declare reduced Capacity and Energy availability under Section 6.6(e)

79.2 REDACTED Has the Seller provided information

**80.0 Reference: EPA Filing, Exhibit B-1, Tab N and BC Hydro Website re Green IPPs and
Customer Generation**

80.1 Please compare, preferably in table form, the EPA vs. the EPAs for Green Energy and Customer Generation on the BC Hydro website as at December 8, 2004, as to the following terms and conditions, and justify the more stringent terms and condition of the EPA on an item by item basis:

80.1.1 Term and term renewal rights (EPA Articles 2.1, 2.2).

80.1.2 All financial security and LD requirements (type, purpose, magnitude per MW or MWH, and whether per MW number is based on dependable capacity or total capacity). Please ensure all items in EPA Articles 13 and 14 are included.

80.1.3 Step in Rights (Article 16 in EPA).

80.1.4 EPA Support Clause (Article 3.2 in EPA).

80.1.5 Frequency of demonstration tests.

80.1.6 Contractual right and conditions for Seller selling excess capacity/energy to third parties (EPA Article 8.6).

- 80.1.7 Limits on Liability.
- 80.1.8 Damage or Destruction of Seller's Plant (EPA Article 11.3).
- 80.1.9 Step In Rights (EPA Article 16).
- 80.1.10 Change in law or "hardship" provisions (apparently not in EPA).
- 80.1.11 Inclusion or exclusion of sale to third parties outside the EPA as a Deliberate Breach.
- 80.2 Why was the "total constructive loss" approach not used in the EPA Article 11.3 as it is for Green IPPs and Customer Generation?
- 80.3 Please explain why an industrial plant that offered an EPA to BC Hydro under the Customer Generation EPA or the Green IPP EPA on the BC Hydro website would receive a generally more favourable (to Seller) EPA than by bidding on this CFT.