



October 10, 2006
Robert J. Pellatt
Commission Secretary
B.C. Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2V3

Dear Mr.Pellatt:

Re: BC Hydro Revenue Requirements F2007/F2008 Application

Please find attached the IPPBC's policy evidence, as may be supplemented, modified or amended as is necessary, which will be given by IPPBC director(s) to be determined.

The resumes of these director(s) will be forwarded in due course.

Yours truly,

Original signed by David Austin

David Austin on behalf of the IPPBC

Enc.

Cc: All Intervenors, BC Hydro

**BRITISH COLUMBIA HYDRO & POWER AUTHORITY
REVENUE REQUIREMENTS F2007/2008 APPLICATION
EVIDENCE OF THE INDEPENDENT POWER PRODUCERS OF B.C.**

Site C

1. It is not appropriate to create a regulatory asset account for Site C investigation. It is appropriate to expense the cost of investigations so there is continuous regulatory oversight.

2. BC Hydro received regulatory approval for the initial \$1.9 million sought for F2005 for Stage 1 Cabinet approval of Site C expenditures but was denied approval for \$5.5 million sought for F2006.

3. According to section 2.7.4 of its F2007/F2008 Revenue Requirements Application at p2-35:

“Approximately \$3.9 million has been spent on Stage 1 work in F2006. A further \$10 million to complete the Stage 1 analysis is planned for F2007. Assuming all potential areas of investigation are completed, it is expected that BC Hydro could spend \$60 to 65 million prior to a final decision being made to seek regulatory approval to construct the project”

4. This is a significant amount of money yet BC Hydro has not provided evidence that Site C will be a financially viable project that warrants continued investigative expenditures. If a regulatory asset account is created for Site C investigations, then regulatory oversight would be restricted to a certificate of public convenience and necessity (“CPCN”) application, a prudency review relating to recovery of rates when the project is in service and conceivably a determination under section 45(6.2) (b) of the Utilities Commission Act prior to advancing from one review stage to the next.

5. Other than the “conceivable” review under section 45(6.2) (b) the other reviews assume that the project will warrant a CPCN or will be built. If the CPCN is not granted or Site C is not built, this after the fact regulatory oversight will be academic. It is far better to have continuous regulatory oversight so that investigative expenditures are kept under control and detailed information about the project is made public.

C. F2007 Call for Tenders for Electricity

6. It is not clear to the IPPBC whether its concern about the F2007 Call should be presented as part of the B.C. Utilities Commission’s (“BCUC”) review of B.C. Hydro’s F2007/F2008 Revenue Requirement Application e.g. section 8.8.2.3 ‘Managing Calls for Energy’ or as part of the BCUC’s review of the BC Hydro’s 2006 Integrated Electricity Plan (“IEP”) and Long-Term Acquisition Plan (“LTAP”) e.g. section 8.2 “Order Sought”.

7. Because of this uncertainty, the IPPBC will file its policy evidence with respect to the 2007 Call for Electricity in both proceedings.

8. As set out in the BCUC's 2004/05 to 2005/06 Revenue Requirements Decision at page 120:

"... The Commission Panel also recognizes the views of the IPPs that it is essential that they learn as early as possible where there is a significant regulatory concern with respect to any contracts they are entering into with BC Hydro.

The Commission Panel encourages BC Hydro to file pro forma contracts with the Commission for comment prior to the commencement of a competitive process, where practicable. In any case, if BC Hydro desires an efficient and effective regulatory process it is incumbent upon BC Hydro to design its competitive process that there is a reasonable opportunity for the Commission to comment on the terms and conditions of the EPAs prior to the awarding of contracts."

9. It is imperative that all discussions and disputes regarding BC Hydro's 2007 Call including the size, evaluation criteria and contract terms, be subject to regulatory review prior to the commencement of the call. Once a call starts, independent power producers ("IPPs") spend their money responding to it... IPPs do not want an after the fact review such as occurred with respect to the IPP Duke Point power project or the threat of an after the fact review with respect to BC Hydro's 2006 Call. They have no means of mitigating the risk of an after the fact change in rules that could materially affect their prospects of success.

10. In addition to its general concerns about the F2007 Call the IPPBC has specific concerns about the terms of the contract. These terms are contained in the Large Projects contract for the 2006 Call which is posted on BC Hydro's website. The IPPBC recognizes that BC Hydro will conduct extensive stakeholder consultation with IPPs that may address these concerns, however, the IPPBC views them as being of sufficient importance that merits their inclusion in this policy evidence.

Contract Terms

11. Overall, the objectives are simple: to encourage the maximum number of competitors and the minimum amount of attrition, in order to keep the cost of new generation as low as possible and the reliability as high as possible. The method for doing this is also simple: in a nutshell, reduce contract complexity and poor risk allocation wherever possible.

12. In the collective opinion of the IPPBC members, the F2006 Call EPA was a contract which did an excellent job of pulling together a huge number of diverse factors into one central document. However, the resulting contract now contains an unnecessary level of complexity and some inappropriate transfers of risk. There is much that can be done to reduce this complexity and risk, and thereby increase the number and diversity of developers who will be both eligible and willing to participate in the next call.

13. The desire to transfer risk is perfectly understandable from BC Hydro's point of view. However, at some point, this risk transfer oversteps the bounds not only of fairness, but also of economic efficiency. It can actually drive the net cost, to BC Hydro's ratepayers, up instead of down.

14. The key point is that the risks transferred to the IPP developers should be those that are controllable by the individual developer, not those that could be more efficiently dealt with by aggregation.

15. For instance, the timing and cost of construction, the permitting, and the financing are obvious risks that should be transferred to the developers. However, transferring the weather risk to the developers is probably very inefficient, because it can be more effectively dealt with in the aggregate. If all the diverse projects scattered over the different regions of the province are combined into an “insurance pool” the shortfalls in one region or technology will often be mitigated by surpluses in other regions or technologies. As individuals, the developers cannot mitigate their risk by aggregation, so they must allow for the worst case scenario in each individual project. That is not economically efficient for the ratepayers.

The IPPBC sees the following as the key areas for improvement in the 2007 Call.

1. Pricing Complexity

16. Simplify the pricing. The pricing in the F2006 Call is more complex than necessary. It contains a number of overly complicated price signals that serve no useful purpose, because:

- a) These price signals are false. They do not reflect actual costs or damages suffered by BC Hydro, and
- b) The individual IPPs are not in control of the factors that would allow them to act on those price signals.

17. Virtually all of the renewable generation resources attracted in the F2006 Call have no storage, and therefore no control over Mother Nature’s delivery of their “fuel” supply. This is certainly true of wind and run-of-river hydro, and even, to a lesser extent of coal and biomass. They can stop production, if BC Hydro would pay their capital charge, but their capital charge is by far the greatest component of their costs, so there’s really little point to such curtailment.

18. Grouped in with the broad topic of pricing, are liquidated damages for delivery shortfalls, and time-of-delivery pricing. For generation resources without storage plus surplus capacity (like wind and run-of-river hydro), there is no ability to control the time of delivery. Those kinds of price signals are simply ineffective for such resources. The developer must simply raise his bid price in order to compensate for the ups and downs of the pricing regime, and the possibility of liquidated damages.

19. A simple one price system could achieve the same results as all this pricing complexity, and many more developers would have far fewer reservations about participating.

2. More Flexible Commencement and Commercial Operation Dates

20. There are a limited number of contractors and professionals such as engineers, environmental consultants and government permitting staff that are available at any one time to participate in the development of generation projects in B.C. Staggering the commencement and commercial operations dates of project in the same call would result

in a more efficient use of this expertise. The “pig in the python” approach should be avoided wherever possible.

3. Limited Flow-Through of Uncontrollable Costs

21. In the IPP contracts that were executed in the late 1980’s and 1990’s there were limited flow through contracts that covered “extraordinary incremental costs” reasonably and properly incurred and proved by a seller and that arise directly as a result of extraordinary changes to government policy, law and regulation and changes in BCH Hydro (which would now be expanded to include the British Columbia Transmission Corporation) technical requirements. The seller had to prove that these costs weren’t otherwise covered by any other price inflator in the contract.

22. This type of provision should be a feature of the F2007 Call electricity purchase agreement. IPPs have no means of covering these types of long term risks other than to increase their bid price. This is a very inefficient way of dealing with this risk when compared to a limited form of flow-through. This flow-through would only come into effect when an extraordinary event occurs as opposed to an annual payment in the form of a higher bid price to cover its expected, and not its actual occurrence.

4. Bid Qualification and Performance Deposits

23. In the 2006 Call, the IPPBC estimates that in aggregate IPPs posted approximately \$80 million in performance security. There is a very high associated interest cost that IPPs need to recover in their bid prices. A much cheaper alternative would be for prospective bidders to go through some sort of pre-qualification process that would provide some comfort that a prospective bidder had the necessary skills and financial capacity to complete their proposed project(s).

24. Because of matters such as permitting risk, there is no guarantee that a project will be completed. However, to cover off this risk, BC Hydro, as it did in the 2006 could build in an “attrition factor”. Because of the B.C. Government’s stated Throne Speech objective of B.C. Energy self-sufficiency within a decade and current supply demand gap, the probability of BC Hydro acquiring electricity it doesn’t need through over subscription is very low.

5. System losses and Network Upgrade Costs

25. Transmission system costs and losses should be correctly allocated between the IPP and other system beneficiaries.

26. A longer-term approach should be used to determine system losses/upgrades. Currently the first new IPP to trigger an upgrade pays for it all even though subsequent IPPs or other generators or increased loads will benefit from that upgrade.

27. A bidder should be allowed to directly pay for Network Upgrade Interconnection costs.

28. The F2006 CFT approach to calculating the cost of incremental firm transmission and energy losses for “negative bubble areas” should be revised. These are defined bulk

29. areas that draw energy from the grid such that a new generator's electrons would not flow down to the load centre in Vancouver, and so should not be penalized as if they would.

30. Costs and losses should be calculated on an average day and not a peak day basis.

6. Staged Commercial Operation Dates for Multiple Generation Projects

31. The provisions in the 2006 Call electricity purchase agreement did not account for the fact that some generating projects such as wind projects have multiple generators that are going to be individually commissioned. It makes no sense to tie the project commercial operation date, when payment to an IPP for delivered electricity is first made, to anything other than the individual commissioning of a unit. If a unit is in operation for a specified period of time and is generating electricity, the IPP should be paid the full contract price for this electricity. It should not have to wait until a specified amount of capacity is in commercial operation before it receives the full contract price.

7. Underlying Construction Cost Escalation between Bid Date and Execution of EPA

32. A relevant local construction index should be used to address the construction cost escalation risk between the date of the bid and the execution of the electricity purchase agreement... Otherwise bidders are driven to price for the worst case scenario of underlying construction cost levels over which they have no control. Depending on the movement of the index, the final bid price could move up or down.

8. Underlying Interest Rate Escalation between Bid Date and Execution of EPA

33. The bid should be indexed to a relevant government bond rate (i.e. Canada 30 year long bond) to address general interest rate escalation risk between the date of the bid and the execution of the electricity purchase agreement. Otherwise bidders are driven to price to the worst case scenario of underlying general interest rate escalation over which they have no control. The bidder would remain responsible for any change in the project spread (the difference between the underlying government bond and the bidder's final cost of debt, which reflects the project's specific risk premium). Depending on the movement of the underlying government bond, the final bid price could move up or down.