BC Hydro Call for Tenders & Review of EPA
Joint Electricity Steering Committee
Information Request No. 1 to BC Hydro

1. **Reference:** Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L;

   Explanation: The assumed Energy Margin and resulting generation load factor are a significant factor in determining the forecast net portfolio cost and the net present value of the incremental cash flows of the various planning scenarios set out in Table 6 and in the Cost Effectiveness Analysis. In order to evaluate the reasonableness of the assumed Energy Margin, information is required on gas prices, electricity prices, gas transportation, variable O&M costs and system gas, electricity transmission costs and the calculation of the Energy Margin.

   Question:

   a. Provide the variable cost data and calculations in Excel format in a manner that allows the assumptions to be examined and sensitivity analysis to be undertaken to evaluate the Energy Margin and variable costs.
   b. Confirm that the gas and electricity prices in the models provided to Intervenors reflect the prices used in the final evaluations.
   c. Explain how seasonal gas price variations and volatility were reflected in the analysis.
   d. Provide a copy of the source documents or source files for gas (EIA) and electricity price forecasts.
   e. Provide a comparison the 5 gas price scenarios to the EIA Reference Case in printed and spreadsheet format.
   f. Explain how the electricity prices were determined for each of the 25 years of the evaluation.
   g. If the electricity price is based on a spark spread, provide the assumptions, including the assumed market heat rate for each year of the evaluation.
   h. Identify where BC Hydro has altered the gas or electricity price forecasts provided by third parties or used averages or weighted data.
      i. Provide an explanation of why the data was altered and what effect it has on the analysis.
      ii. Provide examples of how the EIA forecast was adjusted for basis differentials and exchange rates for each year of the forecast.
   i. Provide a comparison of the Duke Point Power heat rate to the heat rate of more current CCGT technologies, cogeneration and anticipated future CCGT generation technologies.
   j. Provide a layman's description of the "100% Capital Cost Recovery" scenario and the "25% Capital Cost Recovery" scenario and what they mean in terms of Capacity Factor and Energy Margin.
   k. Provide a monthly "back-cast" analysis of the Energy Margin using the actual gas prices and hourly electricity prices assuming that the Duke Point Plant was operating for the

period December, 2002 to November, 2004 or for the most recent 24 month period for which price data is available.

l. Provide the net present value of the incremental cash flows assuming that Duke Point Power does not run to meet either capacity or energy requirements after the 230 kV transmission line is installed in F2009.
m. Provide the annual cost of:
    i. Keeping the Duke Point Plant ready to run.
    ii. Mothballing the Duke Point Plant.
n. What is the generally accepted reliability of the Frame F7A CCGT:
    i. By the supplier,
    ii. In the industry generally?
o. If the Duke Point Plant is unable to maintain a 97% reliability, is Pristine Power:
    i. In breach of the contract, or
    ii. Subject to defined paymants?

2. Reference: Report, Appendix A – Page 6;

Explanation: BC Hydro has used the Huntingdon-Sumas trading hub as the nearest and most relevant hub. The Sumas hub is generally considered illiquid and producers have recently shown a strong preference for using the Station 2 hub.

Question:

a. Confirm that BC Hydro may be required to purchase gas at Station 2 and assume transportation costs from Station 2 to Huntingdon-Sumas.
b. Did BC Hydro prepare or obtain a forecast of Station 2 gas prices for the CFT analysis or for gas supply management purposes? If yes, provide the forecast in Excel spreadsheet format with comparable Huntingdon-Sumas and EIA prices.
c. Confirm that gas at Station 2 trades in $C.
d. Provide the annual forecast fixed and variable unit and total cost (fuel, MFT) of natural gas purchased at Station 2 compared to the assumed fixed and variable unit and total cost at Huntingdon-Sumas as used in the CFT analysis.
    i. Explain how the Huntingdon-Sumas gas price relates to the EIA Reference Case.
    ii. Explain how the Station 2 gas price relates to the EIA Reference Case.
e. Outline and explain the transportation and gas cost mitigation strategy for gas delivery at the Huntingdon-Sumas hub and delivery point.
f. Quantify and explain how the change in trading hub and delivery point to Station 2 would affect the net portfolio cost and mitigation strategy of BC Hydro.
g. Provide all of the inflation rates and exchange rates used in the CFT analysis and an explanation of how and to what numbers the inflation rates were applied.

3. Reference: Report – Page 10, 11, Table 3, Table 6, Table 8, Appendix H – Page 13, 14, 15; Appendix J; Appendix L; TGVI LNG CPCN, Commission IR 2.48.2 (attached); TGVI LNG CPCN, Application, Page 42; BCUC IR 2.48.2, Page 28;

Explanation: In order to evaluate the reasonableness of the assumed gas transportation costs, additional information is required.

Question:

a. Provide a copy of the correspondence from TGVI setting out the forecast fixed and variable gas transportation costs used in the CFT evaluation.
b. Provide the effect of using a 4.6-5.0% system gas ratio on the TGVI system as set out in the attachment vs. the 2.5% system gas ratio used in the evaluation.
c. Confirm that BC Hydro currently pays a toll equal to 1.25 times the allocated cost of service (including RDDA recovery) and that TGVI has assumed in CPCN IR responses that BC Hydro will pay a gas transportation toll of 1.25 times the allocated unit cost of service, which equates to a toll in the range of $1.00 to $1.07 per GJ at a 100% load factor.
d. Provide the assumed gas transportation contract demand on TGVI that is required to serve Duke Point Power and ICP.
e. Confirm that if BC Hydro did contract for less than the 90 TJ/d as assumed by TGVI, it is likely that the unit toll to BC Hydro would increase proportionately.
f. If TGVI was unable to recover its allocated revenue requirements from core customers, in BC Hydro's experience, is it probable that BC Hydro and other transmission (HPTS) shippers would pay higher tolls to ensure that TGVI recovered its total revenue requirements?
    i. How has BC Hydro factored the TGVI toll risk into the evaluation?
g. Provide the forecast annual firm and interruptible gas volume to the Duke Point project and to ICP.

4. Reference: Report, Page 17, Report, Appendix J, Page 2;

Explanation: BC Hydro has assumed that curtailment and temporary generation would be required for 240 hours.

Question:

a. Provide the load duration curves for 2004 to 2010 to support the hours required.
b. Provide any CFT correspondence or Q&As with potential proponents identifying hours or days of operation required for peaking facilities, siting of peaking facilities including contacting BC Hydro and availability of interruptible gas transportation capacity from TGVI, with dates.
c. Provide any correspondence or Q&As with potential proponents identifying hours or days of curtailment required, location restrictions of curtailment and notice period for curtailment.

5. **Reference:** Report, Table 8; Report, Appendix L, VIGP Benchmark Analysis; Industry Publications & Literature;

Explanation: BC Hydro has indicated, for the VIGP Benchmark, an average Capacity Factor Over the Term of 80%. No information has been provided for Duke Point Power. Information available from industry publications and presentations reflects capacity/load factors that are much lower and distressed asset prices.

"Overbuilt generation, inadequate transmission in some regions; 60+% of proposed plants halted; 60,000 MW of capacity is for sale in the US" Owens, EEI, April 23, 2004

"Large over built markets with 25-40% excess; Merchant electricity sales market may be over built as much as 100%" Apex Power, June 28, 2004

"In May, MatlinPatterson bought for $475 million eight state-of-the-art power plants from Duke Energy Corp. that were originally valued on the company's books at $2.6 billion; Energy profits could quickly fizzle out if new supplies hit the market any time soon and skyrocketing prices fall back to earth." Business Week, November 22, 2004

"As a result of the over-build, the increased cost of natural gas and the reduced, or in some cases, non-existent spark spreads in the last few years, the market value of new combined-cycle gas-fired generating units declined to a level significantly less than the original cost of these units, thus wiping out billions of dollars of capitalization of the merchant generators, pushing some into default or bankruptcy and forcing some to sell their assets at distressed prices, providing a potential new least cost option for some utility buyers." Seligson, K Road Power, July 8, 2004

"The average capacity factor of the 900-plus units built since 2000 is less than 25 percent, and the lion's share of units dispatching as base load came online between 1955 and 1991." Public Utilities Fortnightly, June, 2004

"But in many regional markets, the new gas plants are idle for 75%–80% of the hours of the year,"; Pointing to parts of the U.S. Southeast and Midwest, for example, Lapson noted that CCGTs are expected to operate 20% or fewer of the hours of the year this year, doubling to an estimated 40% to 45% by 2010.; "Longer term, the upward pressure on gas prices may be alleviated by lower power consumption or the construction of power plants using new coal technology," Energy Analects, November 8, 2004

Question:

a. Provide the average capacity factor assumed for Duke Point Power.
b. Provide information available to BC Hydro that provides capacity and reliability factors for CCGT plants in North America.
c. Provide the capacity factor experience of Frame 7FA CCGT generation in NA for each of the last 2 years.

d. Confirm that capacity factors of a generator are in part a function of market heat rate and that directionally, a more efficient generator will run at a higher capacity factor than a less efficient generator.
e. Confirm that new CCGT generation technologies have a higher efficiency than older generation and that the gap would be expected to widen over time as more efficient generation is brought on line.
f. How has BC Hydro factored the market risk such as that experienced by existing gas fired generation into the CFT evaluation?

6. Reference: Report, Page 13-14, 16-18;

Explanation: Additional information is required for the three options: Tier 1, Tier 2 and No Award.

Question:

a. Provide the transmission upgrade costs applied to the Tier 2 (150 MW) option.
b. Provide a detailed description of the Tier 2 resources totalling 122 MW.
c. Did BC Hydro consider the option of Tier 2 and contingency as an alternative?
    a. Provide the NPV of a Tier 2 and contingency option in the format of Table 6 and Appendix J.
d. When BC Hydro revised the VI demand forecast, why did BC Hydro not change the CFT?
e. Provide copies of the presentations to Senior Management in mid-October and the additional analysis provided to Senior Management.
f. Provide the details of any disqualification of bidders and explain why the reasons for disqualification were considered material.
    a. Were the reasons for disqualification potentially as a result of BC Hydro changing the terms or schedule of the CFT?
g. Did the disqualifications alter the Tier 2 capacity options available to BC Hydro?

7. Reference: Not Applicable;

Explanation: Information is required about the total capital expenditures for the Duke Point Power project by all companies and total forecast payments by BC Hydro related to the Duke Point generation.

Question:

a. Provide the forecast capital costs in as spent dollars as follows:
    i. BC Hydro
    ii. BCTC
    iii. Terasen Gas Vancouver Island

b. Provide the total payments in as spent dollars over the forecast 25 year term of the EPA broken down as follows:
    i. Duke Point Power
    ii. Terasen Gas Vancouver Island
    iii. Terasen Gas
    iv. Duke/Westcoast Energy
    v. Gas Supply
    vi. Sales Tax and Motor Fuel Tax
    vii. Electricity transmission other than BCTC
c. Provide the total fixed charges and total variable charges in as spent (nominal) dollars by year for 25 years.

8. Reference: Report, Page 1, 15, 16, 17; Report, Appendix H, Page 1

Explanation: 230 kV - On page 15 BC Hydro refers to an earliest in-service date of October, 2008. On page 16, BC Hydro refers to F2009 and on page 17 to March 2009 as used in the CFT.

HVDC – The CFT and QEM assumes, for planning purposes, that the HVDC lines are retired and the life extension has cost and other risks and uncertainties.

Question:

a. Explain the differences in the 230 kV in-service date.
b. Provide all studies, reports and other documents relating to the earliest in-service date for the 230 kV transmission to VI.
c. Provide all studies, reports and other documents relating to the critical path for 230 kV transmission to VI and identify any activities that are subject to delay or possible advancement. Examples include rights of way and approvals.
d. Provide all studies, reports or other documents relating to the life or reliability extension of the HVDC line to VI that have been undertaken or issued since the VIGP proceedings.
e. If BC Hydro or BCTC have not continued to evaluate the transmission options, explain why.