1.0 Reference: "The capital costs of these projects are amortized equally over the project life." (2.4.1.1 of the IEP, para. 5, pg. 2-13)

1.1.1 Does this mean the same amortization period was used for all generation technologies, or that each different generation technology employed the same amortization period? Was the amortization period used for large hydro (e.g., Site C, Mica, Revelstoke) the same as the amortization period used for small hydro? If not, please explain why.

RESPONSE:

The amortization period for each project or generic bundle was based on the expected useful life ("project life") in the 2005 Resource Options Report (ROR) and is not assumed to be the same for all generation technologies. Examples are:

Combined cycle gas turbine	**25 years**
Small hydro bundles	**40 years**
Revelstoke/Mica new units	**50 years**
Large Hydro	**70 years**

BC Hydro understands that project proponents may choose to use a specific design life for their facilities. In general, there is a relationship between the useful life of a project's major components (e.g. turbine, generator, concrete infrastructure) and assumed investment in sustaining capital. Project proponents may choose a different project life and include different sustaining capital to reflect the chosen project life.

BC Hydro has reflected its understanding of industry practice in its assumptions of expected useful life. These assumptions were reviewed as part of the general 2005 ROR First Nation and Stakeholder engagement.

2.0 Reference: "[Because of its large reservoirs] BC Hydro makes operational choices as to whether to generate from Burrard or to purchase energy from external markets based on their relative costs" (3.2.3 of the IEP, para. 3, pg. 3-6)

1.2.1 Depending on natural gas pricing, exchange rates, capacity at the BC-US intertie and availability of supply from export markets, long term purchases from domestic IPP's are often less expensive than either Burrard generation or the purchase of imports. Are these "operational choices" made to maximize short-term trading profits or to minimize long term costs to BC ratepayers?

RESPONSE:

BC Hydro does not agree with the statement that has been added by Cloudworks Energy Inc. to the beginning of the reference, namely "[Because of its large reservoirs]". Other utilities that do not have large reservoirs can also make operational decisions whether to operate a facility or purchase energy from the market. Further, there is an assertion in the sentence before the question concerning the comparison of domestic independent power producers (IPPs) with Burrard generation and the purchase of imports that BC Hydro does not believe is relevant to the question.

BC Hydro builds its system in light of long-term costs that consider how short-term operations are undertaken. Once the system facilities are in place, decisions to operate are based on minimizing costs to ratepayers in the short-term, while managing risks and recognizing longer term implications.

3.0 Reference: "[Because of its large reservoirs] BC Hydro makes operational choices as to whether to generate from Burrard or to purchase energy from external markets based on their relative costs" Section 3.2.3 of the IEP, para. 3, pg. 3-6

1.3.1 Please explain the advantages and disadvantages to ratepayers of BC Hydro being a net importer from a long term energy cost, energy security and energy reliability perspective.

RESPONSE:

The disadvantages to ratepayers of BC Hydro being a net importer of the spot market include increased and unbounded cost risk through exposure to volatile spot market prices and the potential for higher increased overall costs depending on future gas and electricity prices. Increased reliance on the market also poses additional energy reliability and security risks as there are current transmission constraints to moving additional blocks of electricity between B.C. and Alberta or the U.S. on a firm basis. Page 7-41 of the 2006 IEP also provides that other disadvantages of being a net importer include non-realization of job creation or economic security benefits and little influence over the source and environmental impacts of energy supply. These findings are consistent with those of the B.C. Progress Board in the report "Strategic Imperatives for British Columbia's Energy Future" set out in Attachment 1 to the response to BCUC IR 1.280.2.

The advantages of BC Hydro being a net importer of the spot market include the potential for lower increased overall costs depending on future electricity price scenarios.

For more detail on the advantages and disadvantages of a net import position, please refer to section 7.2.5 of the 2006 IEP for a discussion of the results of the "Security of Supply" portfolio analysis and Chapter 3 of the 2006 IEP for a discussion of the cost and supply risks associated with gas and electricity markets. Based on the results of the 2006 IEP analysis, BC Hydro has chosen to reduce its reliance on the spot market with the Long Term Acquisition Plan's (LTAP) proposal to move towards planning to meet probable load with domestic supply and/or long-term import contracts.

4.0 Reference: "The LTAP is based on the December 2005 Load Forecast. The 2005 Load Forecast has increased in energy and peak demand as compared to the 2004 Load Forecast" (4.3.1 para. 1, pg. 4-10 of IEP)

1.4.1 In September of 2005 Teck Cominco announced it would extend the mine life of it's Highland Valley Copper Mine by 5 years until 2013 (see pg. 16 of Teck Cominco Annual Information Form, March 1, 2006). Is this reflected in the 2005 Load Forecast and the LTAP? If not, how much more energy would the Load Forecast have to increase to accommodate this mine life extension.

RESPONSE:

Yes, the announcement is reflected in the December 2005 Load Forecast, on which the LTAP is based. The forecast assumes Highland Valley Copper's mine life will be extended to the end of the fiscal year (F2014) that correspondes with Teck Cominco's anticipated mine life.

5.0 Reference: "The LTAP is based on the December 2005 Load Forecast. The 2005 Load Forecast has increased in energy and peak demand as compared to the 2004 Load Forecast" (4.3.1 para. 1, pg. 4-10 of IEP)

1.5.1 Does the 2005 load forecast include new load requirements to serve any new mines or smelters being planned for British Columbia?

RESPONSE:

Yes, load growth attributed to the metal and mining sector is shown in Table 10.1 of the December 2005 Load Forecast (Appendix K-2, Exhibit B1-C).

6.0 Reference: "The assumptions for the 2006 IEP load resource balance are that Burrard will be relied on to: supply three units of dependable capacity (457 MW) and firm energy (3,050 GWh/y) until 2009, and then; provide six units of dependable capacity until the end of 2014; and supply six units (6,100 GWh/y) of firm energy until the end of F2014." 4.4.3.4 (pg. 4.24 of the IEP)

1.6.1 In recent years Burrard has operated at a fraction of its capacity, presumably because imports have cost less than Burrard generation. Please show a table that illustrates on a quarterly basis over the past 5 years in three columns - (1) the average cost of US imports ($CDN/MWh delivered LM), (2) the implied average cost of Burrard energy based on the average quarterly SUMAS gas price and Burrard's heat rate and (3) the average cost of purchases from EPA's with domestic IPP's. Which of the three sources is cheapest? Least volatile? Most reliable? Cleanest? The largest contributor to provincial property taxes and fees? Creates the most employment? Provides First Nations with the most benefits?

RESPONSE:

The following table outlines the following three values on a quarterly basis over the past five years - (1) the average cost of US imports ($CDN/MWh delivered to the Lower Mainland), (2) the implied average cost of Burrard energy based on the average quarterly SUMAS gas price and Burrard's heat rate and (3) the average cost of purchases from EPAs with domestic IPPs.

	(1) Average Cost of Imports[1]	(2) Implied average cost of Burrard energy [2]	(3) Average cost of purchases from EPAs with domestic IPPs[3]
Q1 F2002	n/a	67	95
Q2 F2002	n/a	36	52
Q3 F2002	n/a	39	52
Q4 F2002	n/a	40	44
Q1 F2003	n/a	43	57
Q2 F2003	n/a	36	53
Q3 F2003	n/a	62	63
Q4 F2003	64	85	60
Q1 F2004	45	69	65
Q2 F2004	54	63	59
Q3 F2004	50	63	60
Q4 F2004	57	69	60
Q1 F2005	57	73	62
Q2 F2005	57	67	61
Q3 F2005	55	74	60
Q4 F2005	61	74	63
Q1 F2006	53	78	66
Q2 F2006	48	98	62
Q3 F2006	72	124	73
Q4 F2006	63	81	70

Notes:

1. The average cost of imports delivered to BC was calculated using the TPA, a copy of which is attached to the response to IPPBC 1.6.2. Prior to F2003, no allocation was made between BC Hydro and Powerex regarding the value and accountability for imports and thus the calculation of average cost of market purchases for F2002 would reflect all of Powerex's purchases, not just those delivered to B.C., and thus has not been provided. From Q1 F2003 through Q3 F2003, imports during that period were allocated to the trade account so no price is associated. Please also refer to the response to IPPBC IR 1.6.1.

2. The cost of running Burrard is based on the average quarterly Sumas gas price and Burrard's full load heat rate (10.56 GJ/MWh), fixed OMA ($1.87/MWh), taxes (7.5 per cent) and a firm energy capability of 3,050 GWh/year.

3. The average cost of purchases from EPAs with domestic IPPs includes the cost of Alcan, Arrow Lakes, miscellaneous small IPPs and Island Cogeneration Project.

7.0 Reference: "The assumptions for the 2006 IEP load resource balance are that Burrard will be relied on to: supply three units of dependable capacity (457 MW) and firm energy (3,050 GWh/y) until 2009, and then; provide six units of dependable capacity until the end of 2014; and supply six units (6,100 GWh/y) of firm energy until the end of F2014." 4.4.3.4, pg. 4-24 of the IEP

1.7.1 Although no final decisions have been made regarding investing in, or repowering, the Burrard thermal plant, the IEP assumes dependable capacity and firm energy available from that facility will double in 2010. Please explain.

RESPONSE:

The LTAP proposes a plan that if approved and executed, would be sufficient to replace Burrard's contribution of energy and capacity to the system by F2014. This is likely the minimum realistic timeframe to acquire the resources and have Interior to Lower Mainland transmission in place.

Burrard has six units that are available to use when they are required and if they are economic. In the operating time frame (F2006 to F2009), three of the six units are currently relied upon. Units 4-6 are available to generate electricity as and when required. Units 1-3 are available to generate electricity on notice ranging from four months to two years. The units will be recalled if they are required and if they are the most cost-effective alternative.

8.0 Reference: "Three scenarios for the direct capital cost estimate for Site C: $2.3B, $2.8B, $3.2B in real 2004 dollars." 6.4.2 Table 6-3, pg. 6-18 of IEP

1.8.1 The Province of Quebec recently announced it would invest $25 billion in new hydro dams generating 4,500 MW, implying a cost of $5.6 million per MW (see Province of Quebec Energy Policy, May, 2006). Manitoba Hydro projects its 200 MW Wuskwatim Generating Station would cost $1 billion, or $5 million per MW (see Manitoba Hydro web site). However, using even BC Hydro's highest cost estimate for Site C at $3.2 billion for 900 MW, the cost of Site C is still just $3.6 million per MW. Please explain why capital costs for large hydro projects in other jurisdictions are at least 39% higher than in BC, particularly in light the recent construction inflation in our Province?

RESPONSE:

It is not possible to draw any meaningful comparisons between the costs of hydro-electric facilities in B.C. and those in Manitoba or Quebec based on the above information.

The quoted figures for Site C are direct capital costs in real 2004 dollars which, as described in Section 7.2.3.2 of the 2006 IEP, exclude corporate overhead, inflation and interest during construction. It is not clear what type of dollars have been quoted for the projects in Manitoba and Quebec.

Also, each hydro project is unique in terms of water flow, head, upstream regulation, the amount of storage being developed, the site geology and topography, among other factors. Based on the data provided, it is not possible to normalize for these effects.

As BC Hydro stated in Section 7.2.3.2, the range of costs used in the analysis "may not fully reflect the uncertainty that exists in the potential capital costs for the facility. This is because of the considerable timelines for the project, volatility in construction market conditions, potential design changes and the cost of mitigating impacts on the environment and First Nations."

The range of capital cost estimates were updated in May 2006. Please refer to the response to SCCBC IR 1.22.2.

9.0 Reference: "Three scenarios for the direct capital cost estimate for Site C: $2.3B, $2.8B, $3.2B in real 2004 dollars." 6.4.2 Table 6-3, pg. 6-18 of IEP

1.9.1 BC has experienced hyper-inflation in the construction sector. When were these estimates more recently updated?

RESPONSE:

BC Hydro is unaware of any evidence that B.C. or any part of Canada has experienced "hyperinflation", based on its understanding of the term.

The range of capital cost estimates were updated in May 2006. Please refer to the response to SCCBC IR 1.22.2.

9.0 Reference: "Three scenarios for the direct capital cost estimate for Site C: $2.3B, $2.8B, $3.2B in real 2004 dollars." 6.4.2 Table 6-3, pg. 6-18 of IEP

1.9.2 Do these capital costs include: 1) capital cost of incremental transmission investments required to move Site C energy to the LM including network upgrade costs, the cost of permitting and building new transmission line(s) and cut-plane costs? 2) interest during construction? 3) up-front payments to local communities? Up front payments to First Nations? Legal fees including consultations with First Nations? Property tax during construction?

RESPONSE:

The figures quoted above are direct capital costs only.

The direct capital cost estimates include the cost of transmission to connect to the 500kV transmission system at Peace Canyon.

The direct capital cost estimates do not include interest during construction.

The direct capital cost estimates include certain amounts for mitigation and compensation for environmental and socio-economic impacts.

The direct capital cost estimates include project development costs, which include legal fees.

BC Hydro does not pay property taxes. It does pay grants-in-lieu of taxes, which are included as part of the capital cost during construction.

These elements are considered in Table 1 in the response to SCCBC IR 1.22.2.

10.0 Reference: "In particular, the resource mix analysis is not intended to influence or determine the mix of resources resulting from purchases from IPPs and other third party suppliers. The actual mix of resources purchased from IPPs and other suppliers will be the result of competitive acquisition processes." 7.2.1.1, para 3, pg. 7-4 of the IEP

1.10.1 The first paragraph under 7.2.1.1 states that "The Resource Mix key question is: what mix and volumes of resources should BC Hydro acquire and how should these resources be acquired?" Please reconcile this comment with the reference above. Should it not be up to the market to provide BC Hydro with resource options?

RESPONSE:
The context for the question is provided directly below the question on page 7-3, lines 10 to 17, of the 2006 IEP:

"The Resource Mix analysis is intended to inform the following:

- **What resource mix would result in a least-cost portfolio?**
- **How do the portfolios respond to various risks (e.g., gas and electricity prices and GHG offset costs)?**
- **Is there an adequate amount of BC Clean Electricity and/or Green Energy resources to meet either: (1) the Energy Plan's 50 per cent BC Clean Electricity target; or (2) the entire customer electricity need over the 20-year planning horizon?**
- **What are the trade-offs between costs, risks and other attributes (e.g., land impacts) amongst the portfolios?"**

Currently, for that portion of the load/resource gap to be supplied by IPPs, BC Hydro has structured its proposed calls as open and "all source", with the market providing BC Hydro with resource options. The Resource Mix portfolio analysis showed that there are a wide range of resources that could provide a low cost mix and meet the 50% BC Clean Electricity target. Section 8.4.4 of the LTAP proposes the market ultimately provide BC Hydro with resources through two F2007 and F2009 "all source", competitive calls.

10.0 Reference: "In particular, the resource mix analysis is not intended to influence or determine the mix of resources resulting from purchases from IPPs and other third party suppliers. The actual mix of resources purchased from IPPs and other suppliers will be the result of competitive acquisition processes." 7.2.1.1, para 3, pg. 7-4 of the IEP

1.10.2 The costs reflected in the 2005 Resource Options Report appear very optimistic across all fuel types and project sizes. Has BC Hydro had a contractor confirm these costs within the past year? Ever?

RESPONSE:

The cost information in the 2005 ROR is based on the best available information in mid 2005 as answered in the response to BCUC IR 1.220.2 (Exhibit B-6-4).

As provided on page 2-4 of the 2005 ROR (Appendix F, Exhibit B-1B):

"To solicit resource-specific information from future electricity suppliers, a series of meetings was held with representatives from the Independent Power Producers Association of B.C. (IPPBC). Three sub groups were formed to represent wind, small hydro and thermal. In addition, specific individuals knowledgeable about coal, biomass and geothermal were contracted to provide input and comments about those resource types. Subgroups and resource specific meetings are summarized in Table 2-2".

The small hydro subgroup included representatives from two consulting firms, (Knight Piesold Consulting and Sigma Engineering Ltd.) and four IPPs, including a representative from Cloudworks Energy Inc.

11.0 Reference: "The first action to fill the remainder of the load resource gap will be implementation of the F2006 Call, approved by the BCUC in the 2005 REAP NSP, targeting acquisitions of 2,500 GWh/y. BC Hydro considered a range of 7,500 – 10,000 GWh/y for the remaining volume of private sector acquisitions over the next ten years." Page 7-54, Line 13

1.11.1 What does BC Hydro consider to be the range of lead times, from project conception to commercial operation date, required by private sector developers of projects greater than 50 MW by fuel type (wind, run-of-river hydro, geothermal, large hydro, natural gas, coal, biomass etc.) assuming that Power Purchase Agreements are available and economic for these developers? In order to achieve the private sector acquisitions over the next ten years, when does BC Hydro believe that it will need to award EPAs to these developers to achieve these targets? What percentage of energy (i.e., not number of contracts) awarded BC Hydro EPA's over the past 5 years has actually been built? In light of this attrition should BC Hydro be increasing the size of its calls beyond what it actually needs to achieve its supply targets?

RESPONSE:

Depending on the technology and site BC Hydro estimates a new project can take between 2-11 years to move from being determined technically and economically feasible through to commercial operation date (COD). The following table outlines the range of lead times identified in BC Hydro's 2005 ROR by resource type for projects greater than 50 MW. The duration of time to move from conception to a determination of feasibility is highly project and developer dependent, therefore the suggested range of time for each technology provided below could be extended by one to several years.

Resource Type	Project Lead Times (years)
Wind	**3**
Run-of-River Hydro	**3**
Geothermal	**4**
Large Hydro	**10 – 11**
Natural Gas	**2 – 4**
Coal	**6**
Biomass	**3**

BC Hydro believes it will need to award Electricity Purchase Agreements (EPAs) in 2007 to ensure adequate new private sector supply reaches commercial operation by 2011 through 2013.

As of the end of May 2006, 42 per cent of energy from projects awarded EPAs since 2000 has been built. It should be noted that the majority of the energy currently not in service is from projects awarded contracts in the 2003 Green Power Generation call.

BC Hydro has incorporated a project Risk Assessment process to screen out projects with fatal flaws in the F2006 Call and has also increased the required Performance Security to encourage bidders to self-select. Both of these design aspects have been put in place to reduce the risk of attrition.

In all calls, BC Hydro reserves the right to make additional awards if it is cost-effective to do so. In addition to the volume of projects awarded contracts, attrition can also be addressed by ensuring more advanced and financially sound projects receive awards by setting higher participation thresholds (e.g., participation fees, required state of readiness, Tender Security).

12.0 Reference: Figures 7-5 and 7-6, Resource Mix Portfolios, pgs. 7-15, 7-16 IEP

1.12.1 Figures 7-5 and 7-6 capture the sensitivity of NPV to gas and electricity forecasts, and to an 8% discount rate relative to a 6% discount rate for the different portfolios. Historically, large hydro projects and thermal projects have proven more difficult to permit than green projects. Why does the analysis not vary the discount rate to account for 1) increased permitting risk for large and thermal projects, fuel cost risk (natural gas, coal), 2) increased portfolio risk for concentration of assets (i.e., the risk of planning to acquire large blocks of capacity/energy from one source) and 4) timing risk (uncertainty of depending on a project today that won't be build for some years.

RESPONSE:

In the 2006 IEP, Section 3.5.2, BC Hydro identifies the significant risks and hurdles facing all projects in obtaining siting and permits. The identified risks and hurdles are not limited to large hydro projects and thermal projects, and are generally risks that any developer may face.

Please refer to the responses to BCUC IRs 1.11.1 and 1.104.2 for why the discount rates are chosen and why the analysis does not use different risk-adjusted discount rates for different projects.

13.0 Reference: "For purposes of the 2006 IEP, it was assumed that fossil-fuel-fired generation facilities would be required to offset or reduce GHG emissions intensity to 0.36 tonnes of CO2/MWh." Pg. 3, Appx. D of the IEP.

1.13.1 Why would 0.36 tonnes of CO2/MWh be the floor on GHG intensity for planning purposes? For instance, based on the NPV (6% real rate) over 25 yrs of the Mid-GHG Scenario shown in Table 2 on page 2 of Appendix D, the mid-GHG cost of GHG's would be approximately $22/tonne (real $2005)over the next 20 years. This means that for 1000 Gwh of energy from a thermal project with a GHG floor of 0.36 tonnes of CO2/MWh, a GHG cost of nearly $8 million per year (real $2005) would be not accounted for in the planning process. Based on a conservative private market weighted cost of capital of 10%, this would represent an approximate $80 million advantage in the planning process in favour of thermal generation versus generation from green sources for the same amount of energy, or over half of the capital cost of a new 120 MW CCGT plant capable of producing 1000 Gwh annually. Would a nil cost on GHG emissions between 0 and 0.36 tonnes for thermal projects therefore not represent a significant planning bias in favour of thermal projects over green projects? Given that ratepayers might end up funding this shortfall would it not be appropriate to allocate GHG costs from 0-0.36 tonnes of CO2 per MWh to thermal projects for planning purposes?

RESPONSE:

BC Hydro chose 0.36 tonnes of carbon dioxide equivalent per megawatt hour (CO_2e/MWh) as the greenhouse gas (GHG) intensity target for the First Kyoto Protocol Period (2008-2012), and not for the entire 2006 IEP 20 year planning period. As noted at page 3 of Appendix D to the 2006 IEP (Exh. B-1B), starting in 2013 the facility GHG intensity targets used in the 2006 IEP drop over time in anticipation of advances in the best available technology economically achievable (BATEA) standard.

BC Hydro chose 0.36 tonnes of CO_2e/MWh as the GHG intensity target for the First Kyoto Protocol Period because 0.36 tonnes of CO_2e/MWh is roughly the GHG intensity of a CCGT. As described in the 2006 IEP at pages 3-33, 3-34 and 3-42, Alberta's GHG emission intensity standard for new coal-fired electricity generation facilities, which is the only Canadian GHG emission intensity standard currently in place, is based on the GHG intensity standard of a CCGT. Previous federal discussion papers on the Large Final Emitter system also suggested that

the GHG emissions standard for new power generation facilities be set at 0.37 tonnes of CO_2e/MWh, roughly based on a CCGT.

BC Hydro's planning assumption of a nil cost on GHG emissions between 0 and the GHG intensity target does not represent a significant planning bias in favour of thermal projects over green projects. BC Hydro is not aware of any Canadian or US jurisdiction that has legislated zero GHG emissions for thermal facilities at this time. As set out in the LTAP at page 8-24 (Exh. B-1A) and the response to BCUC IR 2.290.1, BC Hydro will give consideration to the allocation of GHG liability between suppliers and BC Hydro to protect BC Hydro customers from the cost of future GHG regulation. BC Hydro will examine the use of GHG adders as part of the Definition phase of the proposed F2007 and F2009 calls. Any GHG adder will be guided by relevant federal and provincial policy and/or regulations.

14.0 Table 8-1 "Resource Requirement and Supply Plans" Section 8.3, pg. 8-5

1.14.1 The LTAP plans on acquiring 12,500 Gwh of new energy from Calls between 2006 and 2009. For reference, please provide, where possible, a summary of average prices (cost to the utility) of long term energy contracts awarded to IPP's in other Provinces in 2004, 2005 and so far in 2006. If possible, please identify the fuel source specified in these Calls.

RESPONSE:

Listed below is pricing information for some of the long-term energy contracts awarded to IPPs in other Provinces in 2004, 2005 and in 2006. Also included is the price for the Standard Offer Program for Small Generators Connected to a Distribution System proposed by the Ontario Power Authority that is expected to be issued after June 2006.

The published prices of the various calls may not be directly comparable due to how the published prices are presented. Further, a direct comparison of prices amongst the different calls may not be appropriate due to the different terms, conditions, requirements and purpose associated with the different purchases.

Province	Buyer	Call	Eligible Technologies	Published Price for Winning Bids	# of Contracts Awarded
Ontario	**Ontario Power Authority**	**Renewable Energy Supply II (issued 2005)**	**Wind, solar, renewable biomass, bio-gas, bio-fuel, landfill gas or water**	**$86.4 per MWh (COD dollars)[1]**	**9 (975.35 MW signed in 2005)**
Ontario	**Ontario Power Authority**	**Standard Offer Program for Small Generators Connected to a Distribution System (to be issued in 2nd half of 2006)**	**Wind, solar, renewable biomass, bio-gas, bio-fuel, landfill gas or water (10 MW or less)**	**Base price of $110.0 per MWh (COD dollars)[1,]***	**N/A**
Quebec	**Hydro Quebec**	**A/O 2003-01 – 100 MW from biomass (issued 2003)**	**Biomass**	**$67 per MWh (levelized 2007 dollars)[2,] ****	**2 (39.4 MW signed in 2004)**
Quebec	**Hydro Quebec**	**A/O 2003-02 – 1000 MW from wind (issued 2003)**	**Wind**	**$78 per MWh (levelized 2007 dollars)[2,] ****	**9 (990 MW signed in 2004)**
Quebec	**Hydro Quebec**	**A/O 2004-02 – 350 MW from co-generation (issued 2004)**	**Co-generation**	**$74 per MWh (levelized 2007 dollars)[3,] ****	**1 (8.1 MW signed 2005)**
Prince Edward Island	**Maritime Electric**	**N/A**	**Wind**	**$77.5 per MWh minimum (COD dollars)[4,] *****	**2 (40 MW signed in 2006)**

Source:

1. **Joint Report to the Minister of Energy: Recommendations on a Standard Offer Program for Small Generators Connected to a Distribution System, Ontario Power Authority, March 17, 2006**

2. **Hydro Quebec Distribution's Application for Approval of the Proposed 2005-2014 Supply Plan to Regie de l'Energie, File R-3550-2004, Hydro Quebec, May 25, 2005**
3. **Hydro Quebec Filing Demonstration Que Le Contrat Retenue Comporte Le Prix Le Plus Bas Pour La Quantite D'Electricite et Les Conditions Demandees, En Tenant Compte Du Cout De Transport Applicable, File R-3593-2005, Hydro Quebec, December 21, 2005**
4. **Application and Evidence of Maritime Electric Company Limited to Prince Edward Island Regulatory and Appeals Commission, Maritime Electric Company Limited, January 31, 2006**

Notes:

*** Price based on average contract price of awarded Renewable Energy Supply II contracts and adjusted for energy losses and lost economies of scale for smaller projects. Additional performance incentive of $35.2 per MWh (COD dollars) provided to projects offering control of output and a price of $420 per MWh for solar photovoltaic projects.**

**** Prices are inclusive of energy losses and transmission costs.**

***** The minimum price is set by the Renewable Energy Act which was passed in the fall of 2005. The minimum purchase price is the price a utility must pay for energy from wind projects until the utility meets the requirement to provide 15% of its electrical energy from renewable sources.**

15.0 Reference: "Figure 8-2 and Figure 8-4 indicate that reliance on Burrard's energy and capacity contribution will be replaced by F2014. This will occur only to the extent that new supply from calls is cost-effective." Page 8-5, line 3

1.15.1 What analysis will BC Hydro perform to assess whether new supply from calls is cost effective? What risk premium will BC Hydro impose upon imports to account for volatility? Has BC Hydro been provided any indication of what a third party marketer would require as compensation for guaranteeing import prices? What adjustments will BC Hydro make to energy acquired from BC-based generation (which return revenues to the province through jobs, taxes, First Nations Agreements, tenure fees, infrastructure improvements etc) in order to compare against imports? How does BC Hydro propose to deal with the environmental costs (ie., embedded associated with imports of thermal fired generation in this analysis?

RESPONSE:

This IR asks a number of questions which can be grouped into two categories: (1) the cost-effectiveness of calls; and (2) the treatment of imports.

<u>Cost-effectiveness of calls</u>: The term "cost-effective" was defined by the British Columbia Utilities Commission (BCUC) at page 77 of its 8 September 2003 *Reasons for Decision* concerning the Vancouver Island Generation Project as follows:

> **"The principal distinction between most cost-effective and least-cost is the scope of considerations that are relevant … most cost-effective includes consideration of project characteristics such as reliability, dispatchability, timing and location as well as cost or price, in the case of an EPA. Least cost is taken to only include cost or price considerations. … Safety, reliability and other impacts are relevant factors, along with the cost to ratepayers and the impact on the financial capability of the utility".**

BC Hydro accepts the BCUC's distinction between cost-effective and least-cost and has adopted the "cost-effective" standard for all acquisitions given that it is a more comprehensive benchmark which incorporates least-cost but also reflects a broader range of both quantifiable and non-quantitative characteristics.

With respect to the analysis BC Hydro performs to assess whether new supply from calls is cost-effective, BC Hydro notes that the competitive call processes themselves are the primary demonstration of cost-effectiveness. This was recognized by the BCUC at page 13 of its 9 March 2005 *Reasons for Decision* concerning the Call for Tenders for Capacity on Vancouver Island:

> **"… the Commission panel notes that once a competitive market-based process has been undertaken and firm commitments from bidders have been obtained, a competitive process should, in most circumstances, be accepted as persuasive evidence of the cost-effectiveness of the resultant successful bid".**

As described on page 8-22 of the LTAP, the F2007 and the F2009 calls will be "all source" competitive call processes. Thus, the outcome of these calls is expected to provide cost-effective energy supply from IPPs. Furthermore, as set out on page 8-39 of the LTAP, the results of the call processes will be compared to BC Hydro's range of forecast electricity market prices in order to provide a basis for evaluating various resource options (including electricity supply from Burrard).

<u>Treatment of imports</u>: BC Hydro has subdivided its response to the remaining questions in this IR into two "import categories" as follows: (1) imports under firm long-term contracts; and (2) import from the spot market. Further description of distinctions between import types is provided in response to BCUC IR 1.3.2.

(1) *Imports under firm, long term contracts*: As part of the Investigation and Definition phases of the F2007 call, BC Hydro will examine allowing projects located outside British Columbia to bid, subject to securing firm point-to-point transmission to the BC Hydro service area and a risk assessment that incorporates jurisdictional risk (please refer to pages 1-5 of the 2006 IEP, and 8-23 and 8-24 of the LTAP, Exh. B-1A). This issue may also be guided by the Province's updated and expanded Energy Plan as well as the results of BC Hydro's updated jurisdictional comparison that is attached to the response to BCUC IR 1.173.1 (Exhibit B-6-3). That jurisdictional analysis indicates that a number of U.S. state jurisdictions allow out of jurisdiction projects to bid while giving preference in the evaluation process to projects located within the jurisdiction or service area because such projects have, among other things, intrinsic grid reliability values associated with their operations.

(2) *Imports from the Spot Market*: BC Hydro does not expect to rely on additional non-firm spot market purchases in its plans to acquire additional supply resources to replace Burrard's capacity and energy supply contribution. BC Hydro and Powerex will continue to pursue economic sales and purchase opportunities in the short and mid term markets.

16.0 Reference: "A forecasted gap of approximately 2,400 – 11,200 GWh/y and 100 – 1,700 MW in F2025 remains." Page 8-4, Line 22

1.16.1 Why does BC Hydro consider it prudent not to address this gap within the next five years? In view of long lead times required for permitting and high attrition in recent calls, should BC Hydro not plan to meet this gap, or at least some of this gap, with private sector calls in the next five years?

RESPONSE:

The LTAP is a ten year plan and it targets the gap during this period of time. In page 8-1, lines 19-28, of the LTAP BC Hydro states that:

> **"The LTAP seeks to commit additional resources that are required to be built now and, at the same time, remain adaptable to changing course if necessary as events unfold. … Therefore, an important element of the LTAP is to preserve BC Hydro's flexibility by investing now to maintain its ability to secure cost-effective resources as future events unfold.**
>
> **One aspect of this flexible and staged approach is through updates to the LTAP targeted on a two-year cycle to effectively monitor and adjust the LTAP, if necessary, to changing conditions."**

The remaining 2,400-11,200 GWh/y load/resource gap appears in the second 10 year period of the 2006 IEP 20 year period. There is considerable uncertainty with respect to such gap and what may be available to fill that gap. Committing to fill the gap that appears in the second 10 year period in this LTAP would require BC Hydro to make choices too soon and in the absence of necessary facts. Therefore, the risks associated with fully committing to actions today to fill this gap are expected to outweigh any possible benefits.