IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

2006 INTEGRATED ELECTRICITY PLAN AND
2006 LONG TERM ACQUISITION PLAN

DECISION

May 11, 2007

Before:

Robert H. Hobbs, Chair
Nadine F. Nicholls, Commissioner
Anthony J. Pullman, Commissioner

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1.0 THE PROCEEDING

1.1 The Regulatory Process

On March 29, 2006 British Columbia Hydro and Power Authority ("BC Hydro") filed its 2006 Long-Term Acquisition Plan ("LTAP") pursuant to Section 45 (6.1) of the Utilities Commission Act ("UCA", the "Act") with the British Columbia Utilities Commission ("BCUC", "Commission") for review and approval. The LTAP was submitted as Chapter 8 of the 2006 Integrated Electricity Plan ("2006 IEP") whose contents contain background information that supports the development of the LTAP (Exhibit B-1A). An updated LTAP (Chapter 8) was submitted by BC Hydro on August 31, 2006 (Exhibit B-1E). Collectively, the 2006 IEP and the LTAP are referred to as "the Application" and the proceeding as the 2006 IEP/LTAP proceeding. Section 1.0 of this Decision sets out how the Commission conducted its review of BC Hydro's Application.

BC Hydro states that the 2006 IEP is a long-term plan that analyzes and describes how it could meet customer electricity needs over a 20-year planning horizon and the resource options available to meet those needs under a variety of assumptions and risks and that the LTAP is an action plan, supported by the 2006 IEP, which itemizes the actions it proposes to take in the next ten years to meet the future load/resource balance and which identifies new supply, Demand Side Management ("DSM") resources and, at a high level, BC Hydro's new transmission requirements.

In the 2005 Resource Expenditure and Acquisition Plan ("2005 REAP") Negotiated Settlement Agreement ("NSA") approved by Commission Order No. G-103-05 issued on October 5, 2005, BC Hydro confirmed that it would seek regulatory approval of the LTAP, to be included in the 2005 IEP[1], pursuant to Section 45 (6.2) of the Act, and that the evidence in the 2005 IEP that supports the LTAP would be subject to Commission review. In filing the Application, BC Hydro states that it is fulfilling a commitment in the NSA on the 2005 REAP.

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[1] The 2005 IEP was planned for completion by end-November 2005. It was completed in March 2006 and was renamed the 2006 IEP. The 2005 IEP and 2006 IEP are the same document.

In its covering letter to the Application (Exhibit B-1A), BC Hydro stated that there would be considerable potential overlap between the subject of the current Application and that of the F2007/F2008 Revenue Requirements Application (“F07/F08 RRA”), which it proposed to file in late April 2006. Accordingly, BC Hydro suggested a Pre-hearing Conference to address both the 2006 IEP/LTAP and the F07/F08 RRA proceedings.

By Order No. G-37-06 dated April 5, 2006, the Commission established a Procedural Conference on May 19, 2006 to hear submissions on the regulatory process for the review of both the 2006 IEP/LTAP and the F07/F08 RRA filings and set out the dates for Commission information requests to BC Hydro on the 2006 IEP/LTAP and the Intervenors’ information requests to both proceedings on the provision that the balance of the RRA would be filed on or before May 1, 2006 (Exhibit A-2).

By letter dated May 1, 2006, BC Hydro informed the Commission that its filing of the F07/F08 RRA would be delayed until the end of May 2006 (Exhibit B-4) as a result of which the Commission issued Order No. G-51-06 dated May 10, 2006 to extend the timetable for information requests that had been set out earlier in Order No. G-37-06 (Exhibit A-4).

On May 19, 2006 the Commission held the First Procedural Conference to consider the implications of the delay in the filing of the F07/F08 RRA and to hear the submissions from all participants on the draft regulatory timetable, following which the Commission issued Order No. G-59-06 dated May 24, 2006 that set out an Amended Regulatory Timetable leading to the Second Procedural Conference (Exhibit A-5).

On June 30, 2006 BC Hydro filed its Evidence on Project Evaluation (Exhibit B-11) as part of the Application stating that its intention was to facilitate a review of the issues surrounding BC Hydro’s Project Evaluation Methodology based on the regulatory construct for BC Hydro, in particular the cost of capital for BC Hydro. The issue had been a concern in recent hearings for applications for a Certificate of Public Necessity and Convenience (“CPCN”) including the Vancouver Island Transmission Reinforcement Project (“VITR”) Decision, where the Commission had concluded that the appropriate forum to deal with the broad policy evidence on BC Hydro's cost of capital would be the IEP/LTAP proceeding (Exhibit A-36).

Following the Second Procedural Conference held on August 1, 2006, the Commission issued Order No. G-96-06 dated August 3, 2006, which established a Regulatory Timetable to complete the review of the 2006 IEP/LTAP and the F07/F08 RRA (which BC Hydro filed on May 31, 2007) on the basis of the Commission Panel's determination that the two proceedings should not be consolidated, established a Negotiated Settlement Process ("NSP") for the F07/F08 RRA, and directed that the evidence in each proceeding would include the evidence of both proceedings (Exhibit A-15).

At the Second Procedural Conference, BC Hydro and the Intervenors commented on whether or not the Section 71 filing for the approval of the Energy Supply Contracts ("ESCs") from the F2006 Call should be part of the 2006 IEP/LTAP and in the covering letter to Commission Order No. G-96-06 the Commission stated that it anticipated that the Section 71 review would be a separate proceeding from the 2006 IEP/LTAP proceeding (Exhibit A-15).

On August 31, 2006 BC Hydro filed an Amended LTAP (Exhibit B-1E), which contained, *inter alia*, updated load-resource information and the effects of BC Hydro's decision to enter into an Amended and Restated Long Term Electricity Purchase Agreement ("LTEPA+") with Alcan Inc. ("Alcan").

On September 21, 2006, the Commission issued Order No. E-7-06 accepting as ESCs the 38 Energy Purchase Agreements ("EPAs") resulting from the F2006 Call. A number of Intervenors in the 2006 IEP/LTAP proceeding submitted to the Commission that the F2006 Call Report should be filed as evidence whereas BC Hydro submitted that information from the Section 71 review that was relevant to the 2006 IEP/LTAP proceeding was already included in its responses to information requests. By letter dated October 13, 2006 (Exhibit A-27), the Commission directed BC Hydro to file the F2006 Call Report as evidence in the 2006 IEP/LTAP proceeding.

In early October 2006 six Intervenors filed evidence with the Commission:

- Evidence of Mr. Robert Fagan of Synapse Energy Economics and Mr. John Plunkett of Green Energy Economics Group on behalf of the Sierra Club of Canada British Columbia et al. ("SCCBC") (Exhibits C25-11, C25-12);
- British Columbia Transmission Corporation ("BCTC") (Exhibit C7-7);
- World Federalists of Canada ("WFC") (Exhibits C24-3; C24-3A);
- Independent Power Producers of B.C. ("IPPBC") (Exhibit C18-5);
- Marvin Shaffer & Associates on behalf of the Columbia Power Corporation ("CPC") (Exhibit C31-6); and
- District of Kitimat ("DoK") (Exhibit C37-3).

In addition two Intervenors, WFC and Vanport Sterilizers Inc. ("Vanport"), sought leave to file evidence after the deadline for filing established by the Commission. The WFC proposed to file as evidence the Stern Report, commissioned by the U.K. Government into the economics of climate change, while Vanport sought to enter evidence concerning a pumped storage project on the Jordan River.

Both applications were denied from the bench by the Commission Panel on the grounds that the Stern Report covered broader issues that were not appropriate for this proceeding, while Vanport's proposed evidence was "very project-specific" (T8:863).

Pursuant to Commission Order No. G-96-06, the Commission convened a Third Procedural Conference on November 8, 2006 to address, among others, the following matters:

- questions and comments regarding the F07/F08 RRA NSA;
- the issues of public disclosure or confidentiality of the LTEPA+ and whether the legality of the LTEPA+ was within the scope of the proceeding; and
- the Section 71 review process for LTEPA+.
  (Exhibit A-29)

No change with respect to the Regulatory Timetable established pursuant to Commission Order No. G-96-06 was made as a result of the Third Procedural Conference, following which the Commission issued Order No. G-142-06 dated November 10, 2006, which created a separate proceeding for the LTEPA+ filing and which directed that the evidence that had been filed to date in the 2006 IEP/LTAP proceeding and that was filed as Exhibit B-28 at the Third Procedural Conference, should be included in the evidentiary record for the Section 71 proceeding that was established by the Order. At the Opening Oral Submissions on November 14, 2006, the Chair remarked that “the intention is to keep the proceedings separate and the records separate” (T5:444).

By Order No. G-143-06 dated November 10, 2006, the Commission approved the F07/F08 RRA NSA. The following sections of the F07/F08 RRA NSA are relevant to BC Hydro’s Application as they deal with major generation project expenditures.

Section 5 of the F07/F08 RRA NSA states that it “is a comprehensive settlement of all issues arising from the F07/F08 RRA, except for the determination under Section 45(6.2)(b) of the UCA sought by BC Hydro in respect of the Aberfeldie Project at pages 4-3 and Appendix L of the F07/F08 RRA.”

By Order No. G-149-06 dated November 29, 2006, the Commission instructed BC Hydro to submit a CPCN Application for the Aberfeldie Redevelopment Project and, by Order No. C-2-07 dated February 9, 2007, approved the Project.

The F07/F08 RRA NSA found that BC Hydro’s planned capital expenditures in the following amounts and in regard to the following projects are “in the interests of persons within British Columbia who receive, or who may receive, service” from BC Hydro, pursuant to Section 45(6.2)(b) of the UCA:

- $46 million, G3 & G4 stators at GM Shrum;
- $12 million, DC System at GM Shrum;
- $78 million, G1-G4 stators at Mica;

- $58 million, Coquitlam Dam seismic improvements; and
- $67 million, G1-G4 stators at Peace Canyon.

(F07/F08 RRA NSA, para. 18)

The F07/F08 RRA NSA dealt with the Capital Plan Review Process as follows:

> "BC Hydro will file its Capital Plan bi-annually. The Capital Plan will identify all capital expenditures and for the purposes of this provision the term "capital expenditures" will include those demand-side management expenditures that are amortized, in the then-current fiscal period and the following fiscal period, as well as total expenditure and in-service date forecasts for projects underway in those periods. In addition, the Capital Plans will specifically identify projects with gross project costs greater than $2 million on an aggregated basis. These bi-annual filings will satisfy BC Hydro's obligations under sections 45(6.1) (a) and (c) of the UCA.
>
> BC Hydro will file Major Threshold Project applications for determinations under section 45(6.2)(b) of the UCA in regard to Major Threshold Projects that are ready to proceed, supported by detailed ("CPCN-like") business cases. BC Hydro will notify stakeholders of these applications at the time they are filed. Major Threshold Projects are all capital projects with gross project costs, including without limitation contributions in aid of construction, transmission interconnection costs and upgrades and the amount of any First Nations costs attributable to the relevant project, greater than $50 million, plus other projects which BC Hydro believes should have Major Threshold Project application treatment. The Commission will determine whether or not to hold a hearing into such an application, and may designate any process to review Major Threshold Project applications as available under section 45 of the UCA. Equally for straightforward projects the Commission may choose not to hold a hearing.
>
> Projects in Capital Plans or Major Threshold Project applications designated as requiring a CPCN by the Commission under section 45(5) of the UCA, or requested by BC Hydro, will be filed as CPCN applications."
>
> (F07/F08 RRA NSA, paras. 19-21)

The F07/F08 RRA NSA established that a regulatory asset shall be established in respect of Site C expenditures. All Site C expenditures during F2007 and F2008 shall be included in the Site C regulatory asset. The creation of this regulatory asset will not preclude the Parties from raising prudency issues under the UCA with respect to Site C expenditures incurred or to be incurred. BC Hydro confirms that there is no impact from these expenditures on the revenue requirements for F2007 and F2008 (F07/F08 RRA NSA, para. 25).

BC Hydro made the following statement concerning Site C:

> "As set out at page 8-33 of the LTAP, BC Hydro will not proceed to Stage 2 unless Provincial Cabinet approval is obtained. BC Hydro intends to provide further information to the BCUC if or when the Provincial Cabinet authorizes additional work and the Site C Investigation proceeds to Stage 2 of the assessment. In the F07/F08 RRA, page 2-36, BC Hydro recognizes that Site C expenses are exceptional in nature, given the long lead time for the project. Accordingly, BC Hydro is requesting that the Commission authorize the creation of a regulatory asset to provide for capitalization of approximately $10 million budgeted for the Stage 1 analysis between April 1, 2006 and September 30, 2006. The Stage 1 analysis will help inform the Provincial Cabinet's decision about whether to proceed to Stage 2. Stage 2 and Stage 3 costs are provisional pending a Cabinet decision to proceed beyond Stage 1" (Exhibit B-10, BCOAPO 1.55.1).

On November 9, 2006, the Commission issued the Commission Staff Issues List for the 2006 IEP/LTAP proceeding (Exhibit A-30). This document formed the basis for the opening oral submissions, which were heard on November 14, 2006. On November 16, 2006, BC Hydro and the Commission held a public meeting to consolidate the issues list, following which, on November 20, 2006, the Commission issued its Consolidated Issues List for the oral public hearing (Exhibit A-33).

The oral public hearing commenced on November 22, 2006 and closed on January 12, 2007. BC Hydro tendered seven witness panels and SCCBC, BCTC, IPPBC and CPC each tendered a witness panel for cross-examination.

The written phase of the proceeding was originally scheduled to begin with Argument by BC Hydro on February 2, 2007, followed by Intervenors' Arguments on February 16, 2007 and end with Reply by BC Hydro on February 23, 2007. The Oral Phase of Argument, if required, was scheduled for March 14, 2007 (T24:3880-81).

1.2 Throne Speech/Energy Plan

In the Application, BC Hydro had stated that the Application had been developed in the context of the 2002 Energy Plan while acknowledging that an update to the Energy Plan was being developed and that the "updated and expanded 2006 Energy Plan may include new conservation targets, among other things" (Exhibit B-1A, p. 1-3)[2]. At the commencement of the oral hearing, the Chair had said:

> "The Panel concludes that it need not at this time deal with issues including process issues that may arise from an update to the Energy Plan. If and when further policy directions from the provincial government are announced that may affect issues within the scope of this proceeding, the Commission will provide an opportunity for participants to make submissions regarding the relevance of the new policy directions to the matters in this proceeding, and to the appropriate procedural changes to take them into account" (T7:610).

At the Opening of the Third Session of the 38th Parliament of the Provincial Government on February 13, 2007, the Speech from the Throne ("Throne Speech") outlined a series of policy statements from the new Climate Action Plan and the updated Energy Plan. On the same date, the Commission communicated a proposal to all participants that Intervenors address matters arising from the Throne Speech in their submissions due on February 19, 2007 and that BC Hydro be given the same opportunity in its Reply due on February 26, 2007. All parties were invited to comment on this proposal by February 14, 2007 (Exhibits A-42, A-43).

Six Intervenors and the BC Hydro responded to the Commission proposal. By letter dated February 15, 2007, the Commission concluded that the Throne Speech be entered as evidence in Exhibit A2-26 and extended the date of filing for Intervenors' Arguments from February 16, 2007 to February 23, 2007 to allow Intervenors, if they so wished, to consider the Throne Speech in their Arguments. Accordingly, the date of filing of Reply was also extended from February 23, 2007 to

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[2] The update to the Energy Plan was initially scheduled to be issued by the provincial government in 2006 and was referred to as the 2006 Energy Plan by BC Hydro. The Update was issued on February 27, 2007, after the close of the oral phase of the proceeding. The 2006 Energy Plan and the 2007 Energy Plan refer to the same document.

March 5, 2007 to allow BC Hydro, if it so wished, to incorporate changes to the Application and its Argument if such changes arose from the Throne Speech as well as to reply to the submissions of Intervenors (Exhibit A-44).

On February 27, 2007, the Provincial Government issued "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan"). On the same date, the Commission communicated by letter a proposal to all participants that Intervenors could address matters that may arise from the 2007 Energy Plan in supplemental submissions that would be due on March 2, 2007; and BC Hydro, in Reply as well as replying to the submissions of Intervenors, could identify and incorporate changes to the Application and its Argument if such changes arise from the 2007 Energy Plan. A two-day extension to March 7, 2007 was proposed for BC Hydro. All parties were invited to comment on this proposal by February 28, 2007 (Exhibit A-45).

In response, BC Hydro submitted that the 2007 Energy Plan is a significant document that will require several months at a minimum to consider fully and that the 2007 Energy Plan should not form part of the 2006 IEP/LTAP proceeding either by way of evidence or submissions, and that 2007 Energy Plan would be more appropriately dealt with as part of its next LTAP filing (Exhibit B-151).

BC Hydro's submissions were supported by the Joint Industry Electricity Steering Committee ("JIESC") (Exhibit C15-20), the Commercial Energy Association ("CEC") (Exhibit C6-9), the British Columbia Old Age Pensioners' Organization et al. ("BCOAPO") (Exhibit C4-20), the CPC (Exhibit C31-17), and the IPPBC (Exhibit C18-38). The SCCBC submitted that the 2007 Energy Plan was within the scope of the current proceeding but remained concerned that the proceeding be brought to closure (Exhibit C25-24). Only the Energy Solutions for Vancouver Island Society ("ESVI") made submissions that the 2007 Energy Plan be allowed as evidence and that Intervenors could reference that document in their supplemental submissions (Exhibit C34-11).

In Commission Letter No. L-12-07 issued on February 28, 2007, the Commission determined that the 2007 Energy Plan would not form part of the evidence of the proceeding and that BC Hydro's Reply would be extended until March 7, 2007. The Commission commented that it would determine if an Oral Phase of Argument would be required following receipt and perusal of BC Hydro's Reply (Exhibit A-46).

BC Hydro submitted in its Reply that the pronouncements in the Throne Speech do not trigger any need for changes to either the Order sought or the specific determination requests contained in the LTAP but that the pronouncements did, in its opinion, give rise to the need to reconsider the value of certain requests for Commission endorsement and/or comment, and that it no longer sought Commission comment in relation to any proposed aspect of the 2007 Call design (BC Hydro Reply, pp. 16, 17).

By letter dated March 8, 2007, the Commission determined that an Oral Phase of Argument was not required and that participants who wished to make further comments on matters relating to the Throne Speech addressed by BC Hydro in its Reply could do so on or before March 12, 2007 and that BC Hydro would have the opportunity to respond on or before March 13, 2007 (Exhibit A-47).

Two Intervenors, SCCBC (Exhibit C25-25) and Vanport (Exhibit C39-5) availed themselves of the opportunity to make further comments on matters related to the Throne Speech and by letter dated March 13, 2007 (Exhibit B-152) BC Hydro objected to them both on the basis that they addressed subject matters that did not relate to the Throne Speech.

1.3 Specific Determinations

On March 15, 2007, the Commission issued Order No. G-29-07 which stated that it considered that there was enough information on the record to allow the Commission Panel to make the specific determinations that BC Hydro was seeking, as set out on page 8 of BC Hydro's Argument prior to a Final Order on the remaining determinations and comments sought in the Applications. Accordingly, the Commission determined that the specific determinations set out on page 8 of BC Hydro's Argument should be accepted pursuant to Section 45(6.2)(b) of the Act and that the reasons for decision for the determinations would be included in these Reasons for Decision.

The following expenditures were determined to be in the interests of persons within British Columbia who receive, or who may receive, service from BC Hydro:

(i) $1,700,000 required to undertake and complete the Definition phase work of Energy Efficiency (“EE”) 3, 4 and 5, including completion of an updated Conservation Potential Review (“CPR”);

(ii) $800,000 for the electricity savings associated with the Greater Vancouver Water District micro-hydro Load Displacement (“LD”) 2 project;

(iii) $2,875,000 to undertake and complete the Identification, Definition and Implementation phase work for the 2007 Call;

(iv) $520,000 required to undertake and complete the Identification phase work for the 2009 Call;

(v) A total of $12,500,000 required to complete the Definition phase of Revelstoke Unit 5 in the years F2007 and F2008; and

(vi) A total of $3,000,000, $1,000,000 in F2007 and $2,000,000 in F2008, required to complete the Identification and Definition phase work for the next Revelstoke or Mica unit.

2.0 BACKGROUND AND APPLICATION

This Section first outlines the energy policy changes of 2002 and the subsequent amendments to the UCA in 2003, and describes BC Hydro's early efforts to respond to the new resource planning requirements. The current Application is then discussed in the context of BC Hydro's planning guidelines and objectives, and stakeholder engagement and the Orders sought are described. Finally, the future regulatory review process is addressed.

2.1 Historical Background

2.1.1 The 2002 Energy Plan

BC Hydro states the Provincial Government's "Energy for Our Future: A Plan for BC" was issued on November 25, 2002 ("2002 Energy Plan") and contains four cornerstones as well as 26 "Policy Actions" that are designed to accomplish the objectives of the Plan, which provide context for the Commission's review of its rates and long-term resource planning.

The four cornerstones of the 2002 Energy Plan are:

- low electricity rates and public ownership of BC Hydro;
- secure, reliable supply;
- more private sector opportunities; and
- environmental responsibility and no nuclear power sources.

A significant number of the Policy Actions involve the Commission and its regulation of BC Hydro. Specifically, Policy Action No. 9 set out the requirements for public utilities such as BC Hydro to complete resource plans for regulatory review (Exhibit B-1B, Appendix A).

The 2002 Energy Plan was updated by the 2007 Energy Plan, which was issued after the close of the Oral Hearing and does not form part of the record of the 2006 IEP/LTAP proceeding. However, the February 13, 2007 Throne Speech that highlights the policy directions of the 2007 Energy Plan was admitted as part of the record (Exhibits A-44, A-46).

2.1.2 The Amendments to the UCA

In order to implement the 2002 Energy Plan, Section 45 of the Utilities Commission Act ("UCA" or "the Act") was amended, and on May 29, 2003, Sections 45(6.1) and (6.2) of the UCA came into force. Section 45(6.1) requires public utilities to file, "in the form and at the times required by the Commission", the following plans:

(a) a plan of the capital expenditures the public utility anticipates making over the period specified by the Commission;

(b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose; and

(c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.

Upon receipt of a plan filed under Section 45(6.1) of the UCA, Section 45(6.2) gives the Commission the discretion to:

(a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in that plan;

(b) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who received, or who may receive service from the public utility; and

(c) determine the manner in which any expenditure referred to in the plan can be recovered in rates.

Subsequent to the amendment of Section 45 of the Act and following a stakeholder consultation process, the Commission issued its Resource Planning Guidelines ("Guidelines") in December 2003 to assist public utilities in the development of their resource plans (Exhibit A2-21).

The Commission stated that its mandate to direct and evaluate the resource plans of energy utilities was intended to facilitate the cost-effective delivery of secure and reliable energy services and that the Guidelines outlined a comprehensive process to assist the development of such plans. The Commission noted that the Act was amended to provide the Commission with a mandate to implement the policy actions of the 2002 Energy Plan and that the amendments to Section 45 of the Act expand upon and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate.

The Guidelines do not alter the fundamental regulatory relationship between the utilities and the Commission or mandate a specific outcome to the planning process, nor do they mandate specific investment decisions but rather provide general guidance regarding the Commission's expectations of processes and methods for utilities to follow in developing plans that reflect their specific circumstances (Exhibit A2-21, p. 1).

2.1.3 BC Hydro's 2004 IEP

BC Hydro filed its F05/F06 revenue requirements application ("F05/F06 RRA") in October 2003 and its 2004 IEP and 2004 REAP on March 31, 2004.

BC Hydro stated that its 2004 IEP had been prepared in accordance with the Commission's Guidelines and that it planned to file its IEPs on a bi-annual basis. The 2004 IEP had nine components including an IEP Action Plan which identified initiatives that BC Hydro planned to undertake over the ensuing four years.

BC Hydro also filed its 2004 REAP pursuant to Section 45(6.1) of the Act stating that although the Commission had not prescribed the form or times for filing the above-mentioned plans or specified the capital planning period, it had prepared the 2004 REAP with a view to satisfying the requirements of Section 45(6.1) of the Act and that it intended to file a REAP on an annual basis.

BC Hydro explained that its 2004 REAP was drawn from four sources:

- it employed the two-year capital expenditure plan;
- it incorporated the IEP Action Plan;
- it incorporated the energy costs associated with its EPAs; and
- it adopted a two-year Demand Side Management ("DSM") expenditure plan.

The Commission determined that its Section 45(6.2) review of the REAP would be heard as part of the F05/F06 RRA proceeding and that it expected to commence a review of the 2004 IEP during the 2004 calendar year (F05/F06 RRA Decision, p. 13).

The fundamental difference between BC Hydro and the Intervenors as to whether the 2004 IEP should come under regulatory review and whether the action plan should be long-term rather than short-term as in the REAP continued throughout the F05/F06 RRA hearing.

In the closing days of the F05/F06 RRA hearing, BC Hydro proposed a resource acquisition, DSM and capital plan review process intended to meet the requirements of Sections 45(6.1) and 45(6.2) of the Act. The proposal included, in chronological order: a Resource Options Report ("ROR"), followed by a review thereof; followed by an IEP as context for near-term plans; and a REAP, followed by a review thereof. The REAP was meant to be the short-term plan of BC Hydro's resource-acquisition, DSM and capital expenditures necessary to effect its longer-term plans (Exhibit B-6, BCUC 1.1.3).

Following the public hearing process and during the Oral Phase of Argument in the F05/F06 RRA proceeding, BC Hydro stated that it had accepted "the challenge that [the Chair] provided to it to make suggestions for a process that affords the opportunity for the Commission to review the IEP in a public forum, while still permitting Hydro the flexibility to adapt to changed circumstances and retain the final responsibility to meet its obligation to serve." BC Hydro outlined its proposal to allow for a review of the identification of resource options, i.e., after it has settled on resource options and following its consultation process in connection with those options.

BC Hydro filed a one-page summary of the "Approximate Timing of Planning and Regulatory Filing Milestones" which outlined the steps and timing of BC Hydro's planning process and proposed regulatory review process.

BC Hydro proposed to complete the resource option identification process early in the first quarter of a calendar year and to file a ROR for the Commission's (and stakeholder) review which would include a terms of reference ("ToR") based on the commentary of issues raised during the consultation process. The review process and BC Hydro's planning process would then be conducted in parallel, i.e., the Commission would conduct a public review of the ROR while BC Hydro continued with its IEP process, including ongoing stakeholder consultation in connection with the development of its portfolio.

The Commission adopted the ROR process together with its identification of the essential elements of the ROR, but did not make any decisions with respect to a review of an IEP and noted BC Hydro's position that the ROR review was in addition to the REAP and IEP filing and review process proposed by BC Hydro and that the ROR process, together with BC Hydro's own consultation process, may be sufficient to satisfy the requirements of Section 45. The Commission accepted BC Hydro's position that the process was expected to evolve to meet managerial and regulatory requirements.

In its October 29, 2004 Decision on the F05/F06 RRA, the Commission concluded that the IEP as presented was not susceptible to meaningful review at that time, particularly given the next iteration of the resource planning process and the evolving regulatory review process. The Commission acknowledged the concerns of the Intervenors that there was no opportunity for a robust review of the REAP filing in the context of an IEP that had not been properly scrutinized. In that Decision, the Commission accepted BC Hydro's proposed review process, which was to allow for a review of the identification of resource options. It further approved BC Hydro's proposal that it prepare ToR to establish the scope of the regulatory review of the ROR (F05/F06 RRA Decision, pp. 64, 65).

2.1.4 BC Hydro's 2005 REAP

BC Hydro filed its 2005 REAP pursuant to Section 45(6.1) of the Act in two components. The first component, filed March 7, 2005, consisted of a plan of capital expenditures for F2006 and F2007; a forecast of expenditures for the acquisition of energy pursuant to existing EPAs for F2006 through F2009; and a plan of how BC Hydro intended to reduce the demand for energy purchased from BC Hydro by its customers and a forecast of expenditures for that purpose for F2006 and F2007. The second component, filed with the Commission on July 8, 2005, comprised the "Supplemental F2006 Call Evidence" that addressed the nature of its proposed F2006 Call and the need therefore.

BC Hydro sought Commission approval of the need for the F2006 Call, and Commission comment on the proposed terms and conditions of the F2006 Call ("Terms and Conditions"). The Commission ordered that both components be reviewed by way of a NSP.

As part of the NSP, the parties discussed the 2005 REAP in two separate components: (i) the F2006 Call, and (ii) the capital, existing EPAs and DSM expenditures and were successful in reaching settlements on both components.

The parties unanimously agreed that the F2006 Call was justified in terms of BC Hydro's projected energy requirements and that BC Hydro should proceed as soon as possible with the F2006 Call as set out in the 2005 REAP and evidence filed to date, with certain modifications.

BC Hydro confirmed it would seek regulatory approval of the LTAP, to be included with the 2005 IEP, pursuant to Section 45(6.2) of the Act. Without prejudice to the parties' rights to make submissions on the scope of Commission oversight of the 2005 IEP, the evidence in the 2005 IEP that supported the LTAP would be subject to Commission review, and would reflect the following issues, amongst other things:

- later Commercial Operation Dates ("COD") for large projects;
- the impact of greenhouse gas ("GHG") regulation on resources, including GHG adders; and
- the use of imports for firm supply, and bridging.

The parties to the NSP agreed that with the filing of the 2005 REAP, BC Hydro was in compliance with the requirements of Section 45(6.1) of the Act in relation to the level of development of the planning process underlying in the 2005 REAP; and that the Commission need not exercise its jurisdiction under Sections 45(6.2) (b) or (c) of the Act respecting the 2005 REAP.

BC Hydro agreed, *inter alia*, that it would address Site C, Burrard Thermal Generating Station ("Burrard", "BTGS") and DSM in its 2005 IEP and F07/F08 RRA and that it would establish a public committee to provide advice and input into DSM matters and to conduct a thorough update of its 2002 Conservation Potential Review ("CPR").

Commission Order No. G-103-05 dated October 5, 2005 approved the NSA for the 2005 REAP (Exhibit B-1B, Appendix C).

2.1.5 BC Hydro's 2005 Resource Options Report

By letter dated April 18, 2005, BC Hydro provided information to the Commission regarding its 2005 ROR. The letter included a description of the Stakeholder engagement process, a general description of the 2005 ROR and a proposed form of a regulatory review for the filing.

BC Hydro stated that its proposed ToR would identify those areas and issues where there was disagreement between it and its stakeholders and may be used to establish the scope of the regulatory review of the 2005 ROR. BC Hydro also proposed a written comment process to review the filing, with a Commission Decision on the 2005 ROR by August 31, 2005.

On June 6, 2005 BC Hydro filed a letter with the Commission setting out:

- the proposed ToR to be used to establish the scope of the regulatory review of the 2005 ROR;
- a summary of the written comments received as a part of the formal written Stakeholder commentary and BC Hydro's response to those comments; and
- a complete copy of all written comments submitted as part of the process.

On June 13, 2005, BC Hydro filed the 2005 ROR, which provided information on the attributes of individual resource options, including cost estimates, technical information and environmental and social impacts, together with the expected ranges by resource type of the amount and cost of energy and capacity that would reasonably be expected to be available. The ROR was intended to inform the development of, and be in lieu of a regulatory review of the IEP.

BC Hydro described its purpose as being to:

- fulfill regulatory requirements in the two-year resource planning process;
- describe the characterization of resource options that will be used in the 2005 IEP;

- facilitate a transparent public review of the resource options; and
- document where, based on the Stakeholder engagement, there was broad agreement or disagreement on the resource type characterization.

BC Hydro stated that the ROR was the first regulatory filing in a two-year business planning process, which would encompass the 2005 IEP and the 2006 REAP. The proposed ToR for the regulatory review of the ROR were set out as follows:

- whether BC Hydro should begin to use the Effective Load Carrying Capacity ("ELCC") method to account for the capacity value of energy resources;
- whether BC Hydro should exclude corporate overhead from the cost of resource options;
- whether BC Hydro should exclude from the resource evaluation federal government development subsidies for wind and other renewable generating units announced in the recent federal budget;
- whether BC Hydro should use the same discount rate for different resource options, despite variations in fuel risk; and
- whether BC Hydro ought to reflect actual capital cost uncertainties for conceptual stage projects.

It became apparent in the course of the 2005 REAP and 2005 ROR processes that the ROR/IEP/REAP scheme was unsatisfactory to Intervenors, particularly insofar as it did not include review by the Commission of BC Hydro's long-term plans (Exhibit B-6, BCUC 1.1.3).

At the procedural conference held on June 29, 2005 to discuss the ToR, BC Hydro took the position that the filing of the ROR was intended to make the regulatory process for a s. 45 (6) review more efficient but that there appeared to be little prospect of the regulatory review of the 2005 ROR being expeditious; and it therefore made a request to withdraw the ToR. BC Hydro was directed to file a letter to the Commission to set out its request to withdraw the ToR and for an order confirming that there would be no further regulatory process regarding the 2005 ROR.

By letter dated July 4, 2005, BC Hydro sought an end to the regulatory review of the 2005 ROR process stating that the 2005 ROR had already achieved two of its main purposes: (i) to obtain significant stakeholder input on available resource options; and (ii) to ensure that no suitable resources were inappropriately omitted or prematurely screened out.

In the letter, BC Hydro proposed to file an IEP by the end of November 2005 for information and its 2006 REAP in the latter part of the first quarter of 2006 and planned to seek the Commission's approval of the 2006 REAP and, in addition, the LTAP identified in the 2005 IEP.

BC Hydro submitted that the LTAP and the plans in the 2006 REAP needed to be consistent with each other and more importantly, needed to be informed by one another, and that the regulatory review of both of them needed to be concurrent.

BC Hydro concluded in the letter that the ROR/IEP/REAP process envisaged by it and accepted by the Commission was not at that time workable and sought a Commission order consenting to the withdrawal of the ToR and confirming that there would be no further regulatory process regarding the 2005 ROR.

At the conclusion of the second procedural conference held on July 8, 2005, the Commission approved BC Hydro's requests for the withdrawal of the ToR and that there would be no further regulatory processes regarding the 2005 ROR and by Letter No. L-60-06, concluded the ROR proceeding.

Although the ROR proceeding was concluded without a review, the 2005 ROR itself, as amended, was filed by BC Hydro as a component of its 2006 IEP filing (Exhibit B-1B, Appendix F).

2.1.6 BC Hydro's 2006 IEP/LTAP

The evolving regulatory review process described previously resulted in the filing of the 2006 IEP/LTAP with the Commission on March 29, 2006 (Exhibit B-6, BCUC 1.1.3; BCUC 1.7.1). Details of the regulatory process for the 2006 IEP/LTAP are described in Section 1 of the Decision.

BC Hydro stated that the 2006 LTAP does not comprise the totality of plans it has or will file pursuant to Section 45(6.1) of the Act regarding the 10-year planning period identified in the LTAP and that both bi-annual LTAPs and bi-annual Capital Plans will be filed with the BCUC pursuant to Section 45 (6.1) of the Act. For example, its F2007 and F2008 Capital Plans are contained in the F07/F08 RRA that was filed in 2006 and it plans to seek major project expenditure determinations pursuant to Section 45 (6.2) of the Act for those capital projects which meet the threshold tests of (i) being over $50 million in gross project expenditures; and (ii) being at the development stage where it is about to be implemented (Exhibit B-10, SCCBC 1.1.1; Exhibit B-6, BCUC 1.1.3).

2.2 The Application

2.2.1 Planning Context and Objectives

Resource Planning Guidelines

In the introduction to the Guidelines the Commission states:

> "On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1, (a), (b) and (c) be prepared in accordance with the Guidelines.
>
> The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including "BC Clean Electricity" as referred to in the [2002] Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM"). Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in

> defining and assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service."

The Guidelines offer guidance to utilities under the following headings:

- Identification of the planning context and the objectives of a resource plan
- Development of a range of gross (pre-DSM) demand forecasts
- Identification of supply and demand resources
- Measurement of supply and demand resources
- Development of multiple resource portfolios
- Evaluation and selection of resource portfolios
- Development of an action plan
- Stakeholder input
- Regulatory input
- Consideration of government policy
- Regulatory review

(Exhibit A2-21)

BC Hydro submitted that its 2006 IEP/LTAP conforms with the Guidelines and with standard Integrated Resource Planning ("IRP") practices (Exhibit B-32, p. 3). This assertion was not challenged or contradicted by any of the Intervenors. The CEC submits that "… the exercise undertaken in this proceeding has been of value to the BCUC, BC Hydro and the stakeholders" (CEC Argument, p. 6).

Government Policy

Commission Guideline No. 10 states:

> “**Consideration of government policy**
>
> A resource plan filed in accordance with the UCA and these Guidelines should be consistent with government policy, as it is expressed in legislation (e.g. efficiency standards) or in specific policy statements and directives. Emerging policy issues, such as increased control of emissions, may be addressed as risk factors”
> (Exhibit A2-21, p. 5).

BC Hydro submits that its Application is the first proceeding to test its long-term plans since the release of the Province’s 2002 Energy Plan and since Section 45 (6.1) of the UCA was brought into force on May 23, 2003 (BC Hydro Argument, p. 1).

BC Hydro states that the 2006 IEP/LTAP have been developed in the context of a statutory and public policy framework, and that the statutory and public policy framework it considered encompasses:

- statutory obligations contained within the Hydro and Power Authority Act, the UCA, the BC Hydro Public Power Legacy and Heritage Contract Act, Special Directive No. HC1 (“HC1”) and Special Direction No. HC2 (“HC2”);
- direction established by the Provincial Government pursuant to the 2002 Energy Plan including the four cornerstones of the 2002 Energy Plan:
    - low electricity rates and public ownership of BC Hydro,
    - secure, reliable supply,
    - more private sector opportunities, and
    - environmental responsibility and no nuclear power sources;

        a. regulatory principles and the Decisions and Guidelines of the Commission; and

        b. the values and preferences of First Nations and stakeholders.

(Exhibit B-1A, p. 2-7)

BC Hydro submits that the planning objectives are aligned to the "Four Cornerstones" of the 2002 Energy Plan although it also acknowledges that an update to the Energy Plan was being developed and that "the updated and expanded 2006 [2007] Energy Plan may include new conservation targets, among other things" (Exhibit B-1A, p. 2-8).

BC Hydro defines its planning objectives as providing the basis on which to identify and compare alternative options, and states that its planning objectives for the 2006 IEP are:

- to maximize reliability;
- to minimize financial costs of energy production over the 20-year planning horizon (e.g., average system costs, rate impact, costs, and risk); and
- to minimize environmental risk (e.g. minimize environmental impacts and GHG emissions).

It seeks Commission endorsement of these objectives.

BC Hydro also put the issue of "self-sufficiency" as a guiding principle in the development of the 2006 IEP/LTAP. It has taken into account proposed initiatives from the February 2006 Throne Speech in the 2006 IEP (Exhibit B-1A, p. 7-40; Exhibit B-6, BCUC 1.279.2).

Four other Provincial Government policy documents related to self-sufficiency were also filed in the course of the proceeding, which are intended to lend support to BC Hydro's action plans. They are:

(i) letter from the Ministry of Energy, Mines and Petroleum Resources dated August 28, 2006 to the Commission advising it that electricity self-sufficiency was being addressed in the new Energy Plan under development, and that BC Hydro's ability to exceed the original F2006 CFT acquisition target is an encouraging development that bodes well for the objective of achieving self-sufficiency within the next ten years (Exhibit A-22 Attachment to BCUC 2.1 to WFC);

(ii) the statements of the premier in legislative debates (Exhibit B-21, p. 4876 of Attachment 1 to BC Hydro 1.1.1 to WFC) describing a goal for self sufficiency in the province;

(iii) the statements of the Minister of Energy, Mines and Petroleum Resources at the IPPBC Annual Conference on October 31, 2006 (Exhibit B-36, p. 4 of Attachment A to the Opening Statement of Mr. Elton); and

(iv) the 2007 Throne Speech which highlighted a requirement in the new energy plan for British Columbia to be electricity self-sufficient by 2016 (T5:454; Exhibit A2-26).

(BC Hydro Reply, p. 7)

BC Hydro argues that by accepting the security of supply underpinnings to the LTAP, the Commission will have left the door open for BC Hydro to shift to self-sufficiency (BC Hydro Reply, p. 49).

BC Hydro believes that the “staged and flexible” approach in the long-term demand/supply planning will facilitate the incorporation of new policy directions in its resource and acquisition planning (Exhibit B-1E, p. 8-2).

The Intervenors do not comment on BC Hydro’s policy objectives, other than the CEC which remarks that it takes no issue with the setting out of planning objectives (CEC Argument, p. 6) and notes that “…[a]part from the fact that maximizing reliability probably overstates BC Hydro's objective, which is more appropriately 'meeting reliability criteria' the general layout of BC Hydro's objectives appears to the CEC to meet and reflect the public interest and appears to be infused throughout the IEP and LTAP to varying degrees guiding the planning” (CEC Argument, p. 9).

Commission Determination

The Commission Panel agrees with BC Hydro that it has an obligation as a public utility to provide reliable, cost-effective electricity supply in an environmentally responsible manner, sufficient to meet customer demand and that this obligation should form the basis of its planning objectives.

Stakeholder Engagement

Commission Guideline No. 8 states:

> "**Stakeholder input**
>
> Although utility management is responsible for its resource planning and resource selection process, utilities should normally solicit stakeholder input during the resource planning process. Methods could include stakeholder collaboratives, information meetings, workshops, and issue papers seeking stakeholder response. Utilities are encouraged to focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs" (Exhibit A2-21, p. 5).

To demonstrate the level of stakeholder engagement in the 2006 IEP/LTAP preparation process BC Hydro filed a 286 page document entitled "First Nations and Stakeholder Report" as part of its Application (Exhibit B-1C, Appendix G).

BC Hydro states that, as part of the 2006 IEP process, it prepared the 2006 IEP First Nations and Stakeholder Engagement Plan to ensure that a broad range of stakeholder values and perspectives were captured as part of the IEP process; to seek to elicit input from all BC Hydro's stakeholders; and to provide interested parties with multiple opportunities to become involved in the 2006 IEP process. The plan identified five key engagement streams:

- broad public engagement and communications which enabled BC Hydro to learn about the public's values related to energy planning and keep the public informed throughout the IEP process;
- a First Nations engagement stream to allow BC Hydro to inform First Nations about the IEP process and BCTC's Capital Plan, learn about their values and interests related to electricity planning and resource options, and seek input as to how they would like to be engaged in future;
- a regional engagement stream designed to elicit regional values about energy planning and resource options and to obtain feedback on the resource strategies that emerged as the 2006 IEP process unfolded;

- a technical resource options stream to seek input from those individuals and organizations interested in the technical aspects of resource planning and to ensure that the assumptions and characterizations of all commercially viable resource options were broad, current and representative of the available options; and
- a Provincial IEP Committee (“PIEPC”) whose objective was to work at a more detailed and technical level to understand BC Hydro’s future electricity needs, identify values around electricity planning and consider the implications of tradeoffs between different values.

These streams were implemented concurrently to reach the broadest possible cross-section of First Nations members and stakeholders within the project timeframe (December 2004 to November 2005).

BC Hydro states that many British Columbians from around the province provided their input and comments through public information sessions, regional meetings, technical resource options workshops, First Nations meetings and information sessions, PIEPC meetings, the IEP website, and that through the technical resource options stream, additional resource types were identified which enabled it to gain an improved understanding of the attributes associated with specific resources and that input from this stream supported the 2005 ROR.

The PIEPC looked at key electricity planning questions in more detail, identified values around electricity planning and considered the implications of tradeoffs between different values. Although PIEPC did not achieve consensus on a resource strategy, the members provided valuable input that assisted BC Hydro to prepare the 2006 IEP.

BC Hydro states that, as the IEP process unfolded, it identified five key questions relating to the Resource Mix, Demand Side Management, Site C as a future option, Burrard, and Security of Supply. The portfolio trade-off analysis arising from an analysis of these key questions resulted in the development of four alternative resource strategies that could be used to meet BC’s future electricity needs. Although there was no clear consensus on a preferred strategy overall the various participants provided input which BC Hydro considered in preparing the LTAP (Exhibit B-1C, Appendix G, pp. 1-2).

BC Hydro testified that Intervenors who took part in the public engagement process felt that they needed a separate process from the five different processes that it ran, (public engagement, regional engagement, First Nations engagement, the PIEPC, and technical) and that it is aiming to canvass Interveners to ascertain what it could do better during the process to streamline the regulatory review (T8:1027).

BC Hydro observes that additional planning objectives were raised at regional workshops, which were later defined by the PIEPC but that it did not adopt the PIEPC's additional objectives as its own planning objectives but developed attributes for these objectives and tracked across resource alternatives in the portfolio evaluation process to allow the PIEPC to make trade-off decisions. These additional objectives are:

- to maximize sustainability of energy production;
- to maximize resource diversity of energy sources;
- to maximize regional equity;
- to maximize employment opportunities; and
- to maximize either private or public ownership of energy production (depending on the values of individual members).

(Exhibit B-1A, p. 2-9)

Fourteen attributes were developed and all except one (i.e., employment) could be linked to a particular 2002 Energy Plan objective (Exhibit B-10, BCOAPO 1.4.1). The fourteen attributes are:

(a) Adequate Dependable Capacity

(b) Adequate Firm Energy

(c) Present Value

(d) Rate Impact

(e) GHG Emissions

(f) Local Emissions

(g) Impacted Land Area

(h) Impacted Aquatic Area

(i) Employment

(j) Ownership

(k) Regional Diversity

(l) Technological Diversity

(m) % BC Clean Electricity

(n) % Green Energy

BC Hydro submits that its 2006 IEP was developed with considerable involvement from customer groups, IPP developers and stakeholders and that the second major opportunity for stakeholder input into the 2006 IEP/LTAP was the Commission’s oral hearing process into the 2006 IEP/LTAP, which consisted of 18 hearing days, three procedural conferences, one day for the making of opening statements and the submission of comments on the Issues List for the oral hearing, and the issue of approximately 1,770 information requests (BC Hydro Argument, pp. 4, 76).

No Intervenor challenges this submission. CEC submits: “The record in this proceeding shows ample effort in this regard and BC Hydro is to be congratulated for continuing to evolve its capability and capacity to engage and take constructive input” (CEC Argument, p. 8).

BC Hydro states that as part of the 2005 REAP NSP, it also undertook to establish a public committee to provide advice and input into DSM as well as to update the 2002 CPR. The Electricity Conservation & Efficiency Advisory Committee was set up to provide advice and input on DSM programs, and had its inaugural meeting on September 29, 2006. The broad objectives of the Electricity Conservation & Efficiency Advisory Committee are: to improve the design and delivery of conservation programs; and to model and co-create new and innovative ways of communicating and engaging with First Nations, communities and stakeholders to increase awareness of electricity conservation and efficiency (Exhibit B-139).

BC Hydro states that the External Review Panel for the 2007 CPR was being finalized while the proceeding was taking place (Exhibit B-6, BCUC 1.213.1; T20:3077; BC Hydro Reply, p. 24) and that its objective is to estimate potential energy and capacity savings over the next 20 years among its customers (Exhibit B-126) with the final CPR report being expected to be complete by F2008.

Commission Determination

While the Commission Panel agrees that BC Hydro appropriately engaged its stakeholders, the Commission Panel questions the efficacy of BC Hydro's use of stakeholder input. The Guidelines state that "utility management is responsible for …the resource selection process." The Commission Panel expects BC Hydro to prepare future IEPs using objectives that it has endorsed. Other objectives may be used in dialogue with stakeholders and be the subject of an appendix to the IEP. While there may be value in developing attributes to reflect stakeholder objectives, the Commission Panel also concludes that these attributes should not be carried forward into the IEP proceeding unless they have been adopted by BC Hydro for objectives endorsed by BC Hydro.

2.2.2 Contents

BC Hydro's Application comprises its 2006 IEP and its 2006 LTAP. The LTAP forms Chapter 8 of the Application and is backed up by the IEP.

BC Hydro submits that it has a statutory obligation to supply service to both existing customers and new customers, and that as a result of this obligation, it must:

- plan for customer demand now and into the future;

- be prepared for emerging issues, unexpected events and uncertainties that may put plans at risk; and
- be cognizant of the needs and interests of its current and future customers, the Provincial Government, regulatory agencies, and stakeholders.

This overall purpose drives the need for, and substance contained in, the 2006 IEP/LTAP. BC Hydro submits that the purpose of the LTAP is to identify sufficient resources to reliably serve the growing demand for electricity service within its service area and to inform and guide its resource acquisition processes over the first ten years of the 20-year 2006 IEP study horizon. BC Hydro's Chief Executive Officer testified that the LTAP is:

> "… a very important application for BC Hydro and for our customers, because the planning strategies we put in place will have effects for many years to come" (T7:627).

(BC Hydro Argument, pp. 2-3).

IEP

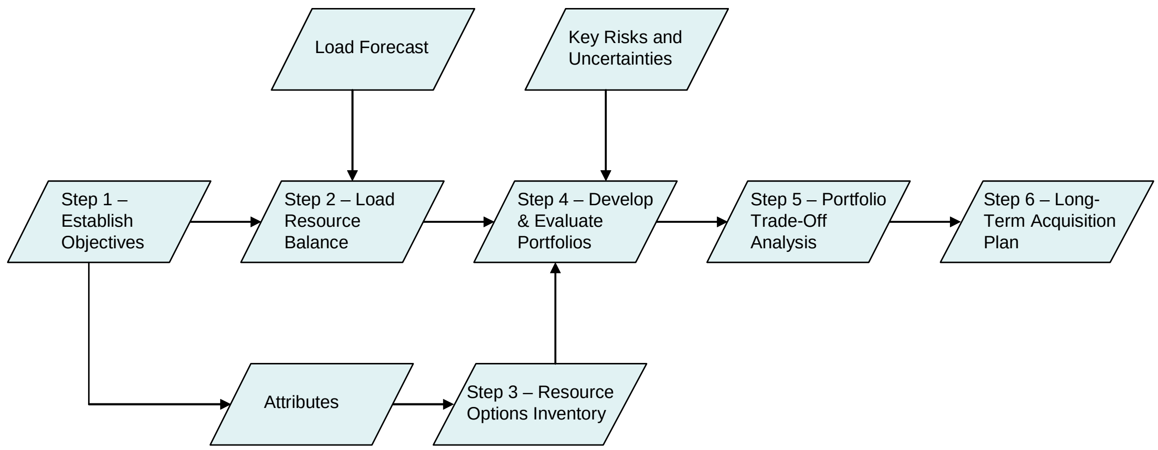
BC Hydro submits that its 2006 IEP is contained in Chapters 1 through 7 of the Application and that the layout and analytical approach of the 2006 IEP conforms to the Guidelines and to IRP standard practices and:

- examines the material risks and uncertainties inherent in the BC Hydro planning context;
- sets out a range of load forecasts both pre- and post- DSM;
- analyzes the load/resource balance;
- identifies feasible, realistic resource alternatives.
- develops several plausible resource portfolios;
- tests those resource alternatives against measurable future risks and uncertainties through portfolio trade-off analysis; and

- concludes with a preferred acquisition strategy that best meets the objectives of low cost and low rate impact, reliable service and low environmental risk.

BC Hydro states that the 2006 IEP involved a number of distinct steps, as set out and described below (BC Hydro Argument, pp. 3-4).

2006 IEP Planning Process



(Exhibit B-1A, p. 1-9)

Step 1 - Establish clear planning objectives. In Chapter 2 of the IEP BC Hydro describes its 2006 IEP planning process, including planning objectives and reliability criteria, and attributes.

The Commission Panel reviews the planning objectives in Section 2 of this Decision.

Step 2 - Develop a 20-year load resource balance. In Chapter 4 of the IEP BC Hydro presents its December 2004 and December 2005 Load Forecasts over the next 20 years and compares them to existing and currently planned resources to establish the need for new resources. These forecasts were updated by BC Hydro twice during the proceeding as part of its biennial review process.

The Commission Panel reviews the load forecast and BC Hydro's existing and committed resources in Section 3 of this Decision.

Step 3 - Determine and characterize the resource options that are commercially available to fill the gap. In Chapter 5 of the IEP BC Hydro summarizes the information presented in the 2005 ROR which is attached as Appendix F to the IEP, and inventories and characterizes the demand-side and supply-side options available to it to meet future electricity requirements.

The Commission Panel reviews the resource options in Section 4.1 of this Decision.

Step 4 - Develop alternative resource portfolios and track appropriate attributes. BC Hydro describes portfolios as a sequence of new and existing resources scheduled over the planning period to meet the energy and capacity needs of its customers and uses attributes to measure the performance of alternative resource portfolios against the established planning objectives. In Chapter 6 of the IEP BC Hydro describes how it develops and evaluates resource portfolios, each consisting of a combination of supply-side and demand-side resources to meet its customers' electricity needs, and how key risks and uncertainties are addressed.

The Commission Panel reviews the portfolio and attributes development in Sections 2.2 and 4.2 of this Decision.

In Chapter 3 of the IEP BC Hydro describes key risks and uncertainties that BC Hydro faces in meeting its customers' electricity needs, including a description of BC Hydro's planning and operating environment and the state of B.C. and North American markets.

The Commission Panel reviews the key risks and uncertainties in Section 5 of this Decision.

Step 5 - Examine the expected cost, risks and social and environmental attributes in the portfolio evaluation to help arrive at the LTAP. In Chapter 7 of the IEP BC Hydro presents its portfolio analysis of the trade-offs, and shows how the analysis and input from stakeholder participants with respect to the resource portfolios was used to develop four alternative resource strategies and its resource acquisition strategy.

The Commission Panel reviews the alternative resource strategies in Section 4.4 of this Decision.

Step 6 - Prepare a 10-year LTAP that sets out actions while maintaining the flexibility to adjust to future changes and opportunities. The LTAP specifies the programs, projects and acquisition processes that are needed to meet customer electricity needs arising from the analysis in the 2006 IEP (Exhibit B-1A, pp. 1-9 to 1-10). The LTAP also contains two Contingency Resource Plans ("CRPs") for transmission planning purposes.

The Commission Panel reviews the LTAP in Section 6 of this Decision and the CRPs in Section 7.

BC Hydro states that its 2006 IEP addresses the broad questions of *how much*, *when* and *what* new resources could be advanced to meet customer electricity needs, and that the questions of *when* and *what* can be further subdivided into the following five key questions:

- Resource Mix – what mix and volumes of resources should it acquire and how should these resources be acquired?
- DSM – what volume of energy and associated commitments in reducing demand should it pursue?
- Site C – how does Site C compare as a potential future resource option? While it is the Provincial Government's decision as to whether or not Site C should be pursued, the 2006 IEP contains portfolios that compare Site C with other potential supply alternatives to assist the Government in its decision.
- Burrard– what are the impacts of a plan to: (i) maintain Burrard, (ii) replace Burrard or (iii) re-power Burrard?
- Security of Supply – should it continue to use the wholesale spot market as a component of its supply portfolio?

BC Hydro states that these five key questions were identified by it through discussions with stakeholder participants in the various engagement venues and that within these strategies there was widespread support for pursuing reliable, secure supply and cost-effective DSM. In Chapter 7 of the Application BC Hydro sets out these four alternative strategies together with its resource acquisition strategy, which lays the foundation for the LTAP (Exhibit B-1A, pp. 1-7 to 1-8).

LTAP

BC Hydro submits that the outcome of the IEP is the LTAP, which is a framework of future actions designed to ensure that it continues to provide reliable, cost-effective service with manageable and reasonable risk to its business and customers. The LTAP, backed by the analysis of the 2006 IEP, is both a primary driver in BC Hydro's business planning and resource acquisition processes and a regulatory requirement. BC Hydro proposes to submit an LTAP to the Commission every two years. The LTAP consists of three principal parts.

(i) Load/Resource Balance

BC Hydro submits that the LTAP lays out the load/resource balance and how any gap would be met with the LTAP action items and that with the inclusion of the F2006 Call results, and after ceasing to rely on Burrard for energy or capacity after F2014, but prior to the implementation of the LTAP it calculates that approximately 7,400-11,600 gigawatt hours per year ("GW.h/yr") of energy and 1,000-1,800 megawatts ("MW") of capacity are required to fill the gap between load and existing resources at the end of F2015.

(ii) Action Items

BC Hydro submits the LTAP proposes a significant addition of new resources over the first ten years of the 20-year 2006 IEP study horizon and itemizes the actions to be taken over this ten year period to close the load/resource gap and shield BC Hydro and its customers from unacceptable reliability risk and unacceptable levels of cost and market risk. Those actions proposed by BC Hydro are as follows:

- "First the pursuit of 5,900 GW.h/yr of new DSM resources by F2015. The 2006 IEP portfolio analysis demonstrates that DSM is a cost-effective resource that mitigates exposure to cost risk associated with natural gas and electricity prices, and GHG offset scenarios, and reduces transmission costs and avoids siting risk. The prioritization of DSM is also consistent with First Nations and stakeholder views and Provincial energy policy;

- Second, contracts with IPPs [Independent Power Producers] for new incremental electricity supply. Approximately, 5,100 GW.h/yr is required from IPPs in F2015. Additional acquisitions from IPPs are likely to be required and will be addressed in the next LTAP. Acquisition from IPPs is consistent with Policy Action No. 13 of the 2002 Energy Plan; and

- Resource Smart capacity projects, such as Revelstoke Unit 5, to meet reliability requirements, augment the DSM and IPP supply contributions and maintain operational flexibility."

(BC Hydro Reply, pp. 5-6)

At a high level, the LTAP also identifies BC Hydro's expected transmission requirements.

(iii) Project Evaluation Methodology

The Project Evaluation Methodology sets out BC Hydro's proposed evaluation methodology to compare the relative cost-effectiveness of resource options as they are developed and implemented. BC Hydro submits that the Project Evaluation Methodology appropriately evaluates resources on the value such resources provide to BC Hydro for the costs BC Hydro would incur and ultimately recover from its customers.

(BC Hydro Argument, pp. 5-6).

2.3 Orders Sought

In its Reply, BC Hydro seeks the following orders:

1. An Order stating that the LTAP meets the requirements of Section 45(6.1) of the *UCA* (BC Hydro Reply, p. 9).

2. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $1.7 million required to undertake and complete the Definition phase work of Energy Efficiency (EE) 3, 4 and 5, including completion of an updated Conservation Potential Review (CPR), are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 10).

3. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $0.8 million for the electricity savings associated with the Greater Vancouver Water District (GVWD) micro-hydro Load Displacement (LD) 2 project are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 11).

4. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $2,875,000 required to undertake and complete the Identification, Definition and Implementation phase work for the 2007 Call are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 12).

5. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $520,000 required to undertake and complete the Identification phase work for the 2009 Call are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 12).

6. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $12.5 million in F2007 and F2008 required to complete the Definition phase of Revelstoke Unit 5 are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 13).

7. A determination under Section 45(6.2)(b) of the *UCA* that expenditures of $1.0 million in F2007 and $2.0 million in F2008 required to complete the Identification and Definition phase work for the next Revelstoke or Mica Unit are in the interests of persons within BC who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 14).

8. Approval of the submission of the transmission LTAP plan and CRPs for inclusion in BC Hydro's 2006 Network Integrated Transmission Service ("NITS") update/application (BC Hydro Reply, p. 15).

BC Hydro submits that post-Throne Speech it continues to seek the following:

(i) Commission endorsement of BC Hydro's future regulatory review process proposal, as described in Part IV of the BC Hydro Argument;

(ii) Commission comment on the BC Hydro Project Evaluation Methodology, including revision to the BCUC's decision with respect to the Vancouver Island Generation Project;

(iii) Commission endorsement of the specific project evaluation economic measures outlined in its Argument, namely:

- DSM cost/benefit screening tests where BC Hydro submits that the evaluation criteria it currently utilizes for DSM, namely screening its DSM programs using three cost-effectiveness tests - Utility Cost Test, All Ratepayers Test and Non-Participant Test accord with the Commission's findings in its decision concerning BC Hydro's F05/F06 Revenue Requirement Application are appropriate. BC Hydro requests that the Commission confirm that Directive 60 from the F05/F06 RRA Decision stands without amendment.

- the following financial parameters, recognizing that such parameters may change with changes in the forecasts of the relevant macro-economic indices or other relevant factors:

  - BC Hydro's weighted average debt cost as reflective of the cost of debt for project evaluation, in this proceeding represented as 6.7 percent; and

  - BC Hydro's nominal weighted average cost of capital (WACC) of 8 percent, reflective of an environment of approximately 2 percent inflation (BC Hydro Reply, p. 10).

and

(iv) Commission comment on the 2006 IEP planning objectives of maximizing reliability, minimizing financial costs of energy production over the 20 year planning horizon and minimizing environmental risk (BC Hydro Reply, pp. 16-17).

2.4 Future Regulatory Review Process

2.4.1 LTAP and IEP Filings

BC Hydro proposes that it file an LTAP with the Commission every two years pursuant to Section 45(6.1) of the Act, and an IEP every four years. These IEP filings would accompany every second LTAP filing, and would include an updated ROR (BC Hydro Argument, p. 132). BC Hydro submits that it requires some flexibility in the timing of these filings in order to coordinate them with RRAs, annual budgets and Capital Plans, and in order that its next (2008) LTAP filing can incorporate the 2007 CPR, preliminary Definition phase work on its proposed Energy Efficiency Bundles 3, 4 and 5 (“EE3”, “EE4”, and “EE5”), and the most recent load forecasts (BC Hydro Argument, p. 133).

Most Intervenors support, or do not comment on, BC Hydro’s proposed filing cycle. Terasen submits that BC Hydro’s proposal is appropriate, and that some flexibility should be retained but that LTAPs filed in years without an IEP should include sufficient updated information regarding changes in assumptions, inputs or timing related to the actions recommended by the LTAPs (Terasen Argument, pp. 12-13). CEC supports BC Hydro’s proposed schedule (CEC Argument, p. 7). The JIESC supports BC Hydro’s proposed filing cycle, including the coordination of the various filings, “after the current IEP is brought up to date to reflect the recent Throne Speech” (JIESC Argument, p. 5).

SCCBC supports BC Hydro’s proposed filing cycle, but submits that there should be more certain dates established for the filings, except in circumstances where the Commission approves a BC Hydro application to delay a scheduled filing. SCCBC submits that its proposal would give the Commission control over the process and avoid the many problems associated with slippage. SCCBC submits that the 2007 CPR and preliminary EE3, EE4 and EE5 work should be timed to feed into the development of the 2008 LTAP (SCCBC Argument, pp. 30-34).

BC Hydro also commits to examining the effects of both the Throne Speech and the 2007 Energy Plan in the next LTAP (BC Hydro submission of February 28, 2007), and proposes to provide updates on resource options and on the load/resource balance in the next LTAP (BC Hydro Reply, pp. 20-23).

Several Intervenors submit that the IEP/LTAP review process should be streamlined (Terasen Argument, p. 12; JIESC Argument, p. 7; CEC Argument, pp. 6-7). CEC suggests changes, including moving away from the portfolio concept, and anticipates having an opportunity to provide its suggestions to BC Hydro through a consultation process prior to the next LTAP filing (CEC Argument, pp. 6-7). BCTC submits that the IEP process could be streamlined if BC Hydro gives BCTC the final LTAP and CRPs before filing IEP (BCTC Argument, p. 3).

BC Hydro submits that its regulatory review proposal is a step toward streamlining future IEP/LTAP proceedings, and that it is committed to exploring additional efficiencies with Intervenors through regulatory reform workshops (BC Hydro Reply, p. 3).

2.4.2 Transmission Planning

Regarding linkages to transmission planning, BC Hydro submits that there is a significant level of coordination between BCTC and BC Hydro, and that this coordination is in compliance with the BCTC Standards of Conduct (BC Hydro Argument, p. 135).

BCTC submits that coordination between BC Hydro and BCTC in the IEP/LTAP process was sufficient to ensure that the transmission implications were properly considered and that BCTC was able to undertake a high-level assessment of the resulting transmission reinforcements. BCTC further submits that additional interaction between BC Hydro and BCTC, or a more relaxed Standards of Conduct, would neither have made a substantive difference to the application, nor have resulted in CRPs that consumed less transmission or deferred additional transmission infrastructure (BCTC Argument, pp. 2-4).

The JIESC supports any efforts, including modifications to the Standards of Conduct, to improve coordination between BC Hydro's IEP and LTAP processes and BCTC's capital plan and CPCN processes (JIESC Argument, pp. 5-6).

BC Hydro submits that the existing Standards of Conduct may be too restrictive for optimal coordination of generation and transmission planning and intends to work with BCTC to determine what changes might be beneficial (BC Hydro Reply, pp.66-67).

Commission Determination

The Commission Panel accepts BC Hydro's proposal regarding the timing of IEP and LTAP filings in most respects, and agrees that some flexibility is required regarding filing dates to allow it sufficient time to complete the 2007 CPR and the preliminary EE 3, EE4 and EE5 definition work, and to incorporate those studies, as well as evolving government policy, into its next LTAP. The Commission Panel is not convinced that BC Hydro will be in a position to file a new LTAP this fall and expects BC Hydro to file its next LTAP early in 2008. The next LTAP should respond to BC Hydro's commitments to examine the effects of both the Throne Speech and the 2007 Energy Plan and provide updates on resource options and on the load/resource balance. The next LTAP should also respond to relevant issues raised by the Commission Panel in this Decision.

The Commission Panel agrees that a new IEP should generally be filed every four years and expects BC Hydro to file a complete, new IEP to support the LTAP that it might be expected to file about the end of 2009. At that time, the IEP should fully consider the then-current state of government energy policy and should support the proposed 2009 Call.

The Commission Panel encourages BC Hydro to work with BCTC to determine what changes to the Standards of Conduct may be beneficial.

3.0 LOAD/RESOURCE BALANCE

In its LTAP, BC Hydro projects a load/resource gap and then proposes action items to close the gap. This Section explores the load/resource balance by first reviewing the load forecast, and then examining the existing and committed resources in the context of BC Hydro's planning criteria. Finally, the load/resource balance is considered.

3.1 Load Forecast

The Commission's Guideline No. 2 addresses the development of a range of pre-DSM demand forecasts, and states:

> "In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions the utility can take to influence demand (e.g., rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts. More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. The energy end-use categories used to analyze DSM programs should be compatible with those used in demand forecasting, so that at any point a consistent distinction can be made between demand with and without DSM on an end-use category-specific basis. Thus, the gross demand forecast should be structured in such a way that the savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast"
> (Exhibit A2-21, p. 3).

BC Hydro states that its Electric Load Forecast is produced annually and published in the fall, and illustrates a range of possible requirements over the ensuing 20 years. The forecast is based on several comprehensive end-use and econometric models that use billed data up to March 31 of the relevant year as historical information, combined with a wide variety of economic forecasts and inputs from internal, governmental and third party sources. The forecast outputs are validated through additional tests and information including time series econometric models (Exhibit B-1, Appendix K2, p. xvi).

BC Hydro states that its 2004 Load Forecast was published in December 2004 and was a key input document into the 2006 IEP, and that its 2005 Load Forecast was published in December 2005 and was a key input document into the 2006 LTAP. The 2005 Forecast was updated in February 2006 and used in the Amended LTAP as filed on August 31, 2006 (Exhibit B-1E). The updated forecast differed from the December 2005 Forecast by approximately 200 GW.h, or less than 2 percent of Gross Requirements by F2025. The difference is related to the industrial and commercial classes.

BC Hydro describes the forecast as a 20-year forecast of the Total Gross Requirements for the integrated system, which include domestic load and other utility sales and transmission and distribution losses. Other utility sales relate to commitments such as firm service obligations to Seattle City Light under the Skagit Valley Treaty, sales to New Westminster and FortisBC Inc. ("FortisBC"), and other boundary accommodations such as Hyder, Alaska. Non-Integrated Areas ("NIAs") are not connected to BC Hydro's transmission grid and are not included in the integrated system forecasts. These are served by local generation, and system planning for NIAs is handled at the distribution level. The areas included in the non-integrated sales forecast are Masset, Sandspit, Atlin, Dease Lake, Eddontenajon, Telegraph Creek, Anahim Lake, Bella-Bella, Bella Coola, and Fort Nelson. The non-integrated sales, including Fort Nelson, are about 0.5 percent of the Total Gross Requirements.

BC Hydro states that its forecast peak demand is defined as the expected maximum amount of electricity consumed in a single hour under an average coldest day assumption established as the design temperature. BC Hydro is a winter peaking utility because the system has a greater share of winter heating load than summer air conditioning load. The distribution customer peak is the most sensitive to temperature. The transmission customer peak is considered to be more responsive to external market conditions and changes in demands for BC's key industrial commodities such as wood, pulp and paper and metals.

The December 2005 Load Forecast and the Adjusted Forecast are summarized below:

Reference Forecast Sales by Class With DSM

Energy (GW.h)	F2004/05	F2024/25	Percent Change	AV Annual Growth Rate
Residential	15,620	22,212	42.2%	1.8%
Commercial	14,362	21,278	48.2%	2.0%
Industrial	19,635	23,714	20.8%	0.9%
Domestic Sales	50,787	68,744	35.4%	1.5%
Losses	4,659	6,862	47.3%	2.0%
Gross Requirements per December 2005 Load Forecast	55,747	75,917	36.2%	1.6%
Less: Industrial Adjustment		(217)		
Adjusted Forecast February 2006	55,747	75,700	35.8%	1.5%
Integrated System Peak (MW)	9,762	13,211	35.3%	1.5%

Source: Exhibit B-1-C Appendix K2, page 82, Exhibit B-1-E page 8-11

To assess the sensitivity of the forecast to a number of variables including weather, economic conditions, and electricity prices BC Hydro uses a Monte Carlo simulation model to produce a lower confidence band (10 percent) and upper confidence band (90 percent) relative to the reference forecast. The resulting confidence bands after 15 forecast years are less than 5 percent different from the reference forecast in F2020 (Exhibit B-1C, Appendix K2, pp. 21-23).

BC Hydro stated that by analyzing historical versus forecast adjusted gross requirements from F1990 to F2005 it can demonstrate a historical forecast accuracy of plus or minus 10 percent for 105 of the 111 forecast points considered (Exhibit B-10 BCUC 2.338.1).

3.1.1 Weather Normalization

For the purposes of weather-normalizing energy sales, BC Hydro employs a rolling average of the last ten years of heating degree days ("HDD"), and uses a 30-year rolling average of minimum temperatures for the purposes of normalizing the system peak. However, in modeling the variability of the load forecast BC Hydro uses a Monte Carlo analysis employing 50 years of HDD data.

In explaining the use of the 10-year average of HDD for energy normalization, BC Hydro testified that:

> “We use average normal heating degree days provided by Environment Canada, and assume that the future will look like the past. So we haven’t considered in our analysis potential effects from global warming” (T11:1536).

BC Hydro further explained that the 10-year average was used as a representative sample because it is a reasonably accurate representation of the mean and variance that is expected to occur in the future. Further testimony indicated that BC Hydro was not aware of any internal studies on the long-term trend in HDD (T11:1654-6). However, BC Hydro agreed that the belief of many scientists that the climate was warming and temperatures would continue to rise had at least in part influenced its decision to use a 10-year rather than 30-year average of HDD (T11:1653).

Concerning variability, BC Hydro testified that five years of data might not produce enough variability in HDD, but that it has found that looking at 10 years of data gave the requisite variability in HDD (T11:1658-59).

In contrast to BC Hydro’s use of a 10-year period for energy demand normalization, in the context of stream flows, BC Hydro stated that 60 years is a very short-time from a statistical viewpoint (T11:1551). While recognizing 60 years as a statistically short-time, BC Hydro stated that 60 years was a representative sample for stream flows and 30 years is a representative sample for weather for calculating the peak demand (Exhibit B-6, BCUC 1.23.2).

BC Hydro explained that its Monte Carlo analysis was not aimed at understanding the mean energy load but rather the full range of variability and because of that BC Hydro used a longer period for the Monte Carlo simulation (T11:1654-55).

BC Hydro states that it uses 30-year average weather in forecasting its system peak demand at least in part because it is consistent with the VIGP Decision (Exhibit B-1C, Appendix K2, p. 45). During the proceeding, BC Hydro agreed that the Commission in the VIGP Decision (Exhibit A2-19) was expressing an opinion about its chief concern (the use of 30 years) when choosing a design temperature. BC Hydro further testified that it was attempting to forecast an unbiased estimate of future peaks and that the peak design temperature may be different from the expected or normal coldest annual temperature (T12:1680-81).

Commission Determination

The Commission Panel is concerned that methodologies employed by BC Hydro to choose the appropriate period with which to normalize for weather, and then forecast energy and peak may be inconsistent in that BC Hydro asserts that 10 years of HDD data adequately represents the mean and variability of future weather for normalizing energy usage, but it rejects 10 years of data as not providing enough variability for its Monte Carlo analysis.

In terms of peak forecasting, the Commission Panel concludes that the use of 30 years of data to calculate the peak design temperature for transmission planning is different than what might be used in forecasting the expected system peak based on normal weather.

While BC Hydro believes that global warming trends will increase temperatures, it has not performed any statistical analysis to gauge what the future trajectory might be, rather it has only assumed that the future will look like the last 10 years. Therefore, **the Commission Panel directs BC Hydro to perform statistical analysis to justify its use of historic 10-year data.**

The Commission Panel directs BC Hydro to include with its next load forecast a report assessing if there are statistically quantifiable trends associated with the temperature metrics used to forecast peak and energy demands, and an analysis of whether these trends should be extrapolated or otherwise incorporated for use in predicting peak and energy usage in the future. Whether BC Hydro determines it should continue to use temperatures based on

historical averages or a statistical trend for forecasting peak and energy demand, the Commission Panel expects BC Hydro to provide a clear and consistent rationale for the historical period it uses for calculating averages, estimating trends, or evaluating variability.

3.1.2 Adjustments to the Forecast

Subsequent to the completion of the annual load forecast, BC Hydro made adjustments to the forecast, which it claimed enhanced the accuracy of the forecast. The explanation of these adjustments comprises some six pages (Exhibit B-10, BCUC 2.403.1).

BC Hydro stated that it intends to provide an expanded explanation of adjustments within the main body of future forecasts (Exhibit B-10, BCUC 2.403.2; T11:1640).

3.1.3 Transmission Level Industrial Customers

In preparing the transmission voltage industrial energy forecast, BC Hydro stated that it starts with consultants' studies undertaken to understand the nature of the load in a given sector, in particular the pulp and paper, forestry and chemical industries (T11:1643).

BC Hydro also described its approach as starting with forecasts based on the Conference Board's forecast of GDP. This econometric approach is described as providing an "envelope" which BC Hydro then fills at an individual customer level (T11:1644).

However, BC Hydro also makes adjustments to the forecast outside of the envelope in the case of customers such as Highland Valley Copper, whose closure BC Hydro described as a very large, and more or less known event (T11:1646).

BC Hydro does not perform individual transmission voltage regressions by the sectors listed above (Exhibit B-6, BCUC 1.254.1).

In preparing the peak forecast BC Hydro uses both a top down and bottom up approach in which it prepares a non-coincident transmission peak forecast for each of its transmission accounts. This peak is adjusted for coincidence with the system peak, and combined with the distribution peak, losses, and other utilities' peaks to arrive at the bottom up system peak. The results of the top down approach, which includes a daily peak model, which varies as the cube of temperature, are compared to the results of the bottom up procedure (Exhibit B-1C, Appendix K2, pp. 46-47).

3.1.4 Unbilled Sales

BC Hydro acknowledged that loads including sales volumes are forecast on both an accrued and unaccrued basis. BC Hydro stated that the load forecast included in Exhibit B-1C, Appendix K2 does not include an adjustment for unbilled sales, but that the values shown in Appendix K-2 are adjusted for accruals for unbilled sales and are used as an input to develop the revenue forecast (Exhibit B-10, BCUC 2.391.2). BC Hydro submits that, to the extent that the load forecast does not show unbilled requirements, actual requirements will differ by approximately 200 GW.h/yr which amount it characterizes as "very, very small increments" (BC Hydro Argument, p. 55).

When asked whether adjustments to calculate the accrual were difficult and time-consuming, BC Hydro stated it had developed a procedure that worked on a reasonably automatic basis (T11:1618-19).

When asked if excluding the accrued amount provides useful information that is not available when the forecast is presented including the accrued amount, BC Hydro replied that a forecast of billed sales basis is usually adequate for most purposes, but for financial management purposes forecasts including the accrual are preferred (T11:1622).

3.1.5 Relationship of Load and GDP

IPPBC notes that there has historically been a very close correlation between total electricity sales and Provincial GDP, which BC Hydro is forecasting will grow at 3 percent per year to 2010. IPPBC notes that BC Hydro's Mid forecast grows at only 2.36 percent before Power Smart in the same period. IPPBC suggests that the close historical correlation requires that both growth rates be the same (IPPBC Argument, pp. 12-13).

BC Hydro references testimony that a high correlation between two variables does not necessarily reflect one to one changes in the relationship between the variables (BC Hydro Reply, p. 56).

BC Hydro noted that the correlation between the growth rate of BC Hydro sales and the growth rate of Provincial real GDP was 0.27 while the correlation between total sales and total real GDP was 0.97 (Exhibit B-10, IPPBC 1.3.1).

The BCOAPO states that the current IEP load forecasts are predicated on the assumption of 20 years of uninterrupted growth, and since a 20-year period of sustained strong economic growth has not occurred in the past, apparently the load forecast is overstated (BCOAPO Argument, p. 14).

BC Hydro submits that it is impossible to predict economic cycles with any certainty, but the BC Hydro forecast, based on forecasts by the Provincial Government and the Conference Board of Canada, is reasonable for the entire forecast period (BC Hydro Reply, p. 57).

In addition to the GDP-related concerns of IPPBC and BCOAPO discussed above, the CEC is concerned that the historical variability in the load forecast is not reflected in the variability bands of the forecast. CEC argues that robust planning requires a broader band reflecting BC Hydro's historical ranges of uncertainty. In other respects CEC tends to agree with BC Hydro's methodology (CEC Argument, pp. 18, 19).

BC Hydro states it might share CEC's concern if the load forecast was not updated regularly (BC Hydro Reply, p. 58).

The JIESC accepts the load forecast with DSM savings as sufficiently accurate for the purposes of this proceeding, and has a similar view regarding BC Hydro's methodology (JIESC Argument, p. 10).

No other Intervenor offered its views on the load forecast methodology.

Commission Determination

The Commission Panel accepts BC Hydro's undertaking to provide adjustments to a load forecast within the updated forecast, and in a manner that provides an explanation of the adjustments and reconciliation to the load forecast.

In the Commission Panel's view BC Hydro should improve the presentation of its transmission level industrial forecast by providing an explanation of the value that is added to the forecast by the consideration of consultant reports in the three industrial sectors discussed, when they apparently do not change the "envelope" forecast resulting from the econometric analysis.

The Commission Panel expects BC Hydro to justify the expense of the exercise of attributing load to individual customers, when its next load forecast is filed.

The Commission Panel is concerned about making a customer-specific adjustment to the forecast if there is no evidence as to whether or not the forecast of GDP is already reflective of the adjustment. If BC Hydro finds that an adjustment to the forecast similar to the current adjustment for Highland Valley Copper is required, the Commission Panel requests that BC Hydro also confirm that any such adjustment is not already reflected in the projection of GDP used in forecasting transmission voltage industrial sales.

The Commission Panel does not believe that there is added value to including a forecast of billed sales in load forecasts. While the Commission Panel agrees that the enhanced accuracy may be small, it believes that providing a forecast that includes the accrual will enhance transparency and provide information on a consistent basis for both future IEP/LTAP and RRA Applications.

The Commission Panel agrees with BC Hydro that a high correlation between two variables does not require that the variables vary in a one to one fashion, and therefore does not find merit in IPPBC's argument in this matter. Similarly, the Commission Panel recognizes that BC Hydro's GDP forecast does not purport to be a reasonable predictor of Provincial GDP each year, but rather it is an estimate of the GDP growth rate for the entire 20-year period, and is therefore suitable for the purpose at hand.

Subject to the issues noted above and in Sections 3.2.4 and 6.1.2, the Commission Panel finds that BC Hydro's load forecast has generally been prepared in accordance with the Commission's Guidelines and further accepts that the results of the 20-year forecast are reasonable for the purposes of the 2006 IEP/LTAP. However, the Commission Panel also agrees with the CEC that, based on the evidence, BC Hydro's prospective forecast band is conservative relative to what has been historically experienced. The Commission Panel finds little merit in BC Hydro's assertion that the production of forecast updates produces the required results.

At the time of filing its next annual load forecast, the Commission Panel directs BC Hydro to provide a review of its prospective forecast range as produced by the Monte Carlo simulation, relative to its historical experience. If the two are not substantially the same, the Commission Panel expects BC Hydro to explain in detail the reasons that make its prospective forecast band preferable to the historical.

3.2 Existing and Committed Resources

BC Hydro identifies its pre-LTAP existing and committed resources in Chapter 4 of the Application (Exhibit B-1A) and provided an updated estimate during the proceeding in Exhibit B-44.

This Section discusses the planning criteria associated with the energy and capacity capability of the existing Heritage hydroelectric and thermal systems, including Burrard, BC Hydro's evaluation and identification of capacity reserves, and contributions to the existing and committed resource stack from the Canadian Entitlement ("CE") to the Downstream Benefits ("DSBs"), existing DSM Programs, and the F2006 and previous calls.

3.2.1 Planning Criteria

BC Hydro states that it uses reliability criteria for planning purposes to evaluate when generation resources are required to maintain the reliable supply of electricity and to ensure that there are adequate resources available to meet customer demand and that the reliability criteria are:

- Generation energy reliability planning criterion; and
- Generation capacity reliability planning criterion.

These criteria are used to evaluate the amount of generation resources required to maintain the reliable supply of electricity. In applying its reliability criteria, BC Hydro considers both the peak load and the annual energy demand on its electrical system and uses both criteria to ensure that the resources available to it are adequate to meet its customers' electricity requirements (Exhibit B-1A, pp. 2-21 to 2-22).

3.2.1.1 System Energy

BC Hydro identifies the firm energy from pre-LTAP existing and committed resources, (with the exception of its 2,500 GW.h/yr allowance for non-firm/market energy), in Exhibit B-44, Table 4-9 and submits that the firm energy of its Heritage hydroelectric system is calculated by the simulated inflow energy equivalent associated with the critical water sequence (BC Hydro Argument, pp. 26, 31). The current critical water sequence is the set of stream flows that occurred from October 1940 to April 1946 (Exhibit B-1A, p. 2-24). This set of stream flows, when applied against the generation and storage facilities of the Heritage hydroelectric system, would have produced a single year minimum of 42,076 GW.h (Exhibit B-6, BCUC 1.23.1), and BC Hydro uses a value of 42,600 GW.h for the purposes of defining the firm energy capability of its Heritage hydroelectric system (Exhibit B-1A, p. 4-23).

BC Hydro stated that the water record used for the determination of the firm energy capability of the Heritage hydroelectric system is the 60-year stream flow record between October 1940 and September 2000 and that truncation of the early period of the water record would result in a higher firm energy capability such that, if the 50-year period between 1950 and 2000 were used the estimated firm energy for the Heritage hydroelectric system would be 44,600 GW.h/yr (Exhibit B-6, BCUC 1.24.2.1). BC Hydro testified that studies regarding the retention of the early period of the water record had been performed, and these studies have both validated the data (T15:2262-63) and recommended it be retained because it represents the known critical period applicable to the BC Hydro system (T12:1780). Data are added to the water record in five-year increments as they become available (T12:1779).

Since it is heavily dependent upon its hydro-generation facilities and its assumptions regarding available water are therefore very important, BC Hydro submits that the existing water flow data set has been rigorously scrutinized and is clearly the best available data on which to base critical water calculations (BC Hydro Argument, p. 31), but acknowledged that some data from a period immediately prior the existing data had been rejected because of concerns over its accuracy (Exhibit B6-1, BCUC 1.23.2).

The energy produced by the Heritage hydroelectric system under average water conditions was tested by several Intervenors. BC Hydro estimated that the difference in the capability of the Heritage hydroelectric system under average water conditions as opposed to the most adverse water conditions is 3,900 GW.h/yr (Exhibit B6-1, BCUC 1.24.2.1) and that this resulted in a 3,900 GW.h difference in market exposure between a critical water year and an average water year (Exhibit B-72). CEC acknowledges that water flow variability creates uncertainty in the short term, but submits that it is much more certain over the long-term. CEC claims this increased certainty creates a statistically dependable resource that, over a period of 20 years, could contribute on the order of 70,000 to 80,000 GW.h which is not accounted for in BC Hydro's plans after 2014 (CEC Argument, p. 21).

CEC submits that this leaves the customers exposed to the costs of buying firm and domestic non-firm supply for the dependable resource stack while exporting non-firm energy from the difference between average water and critical water, and suggests that, while it may be prudent for BC Hydro's plans to not rely on this resource being firmed up, the challenge to BC Hydro is to find other, lower cost ways to firm up the supply (CEC Argument, p. 21).

SCCBC submits that the critical period data set used for the determination of the firm energy capability of the Heritage hydroelectric system should include the full 60 years of available stream flow data, augmented periodically by the most recent five years of data (SCCBC Argument, p. 34).

BC Hydro submits that CEC's proposal to firm up the average water flow is not supported by any evidence and contravenes BC Hydro's generation energy reliability criterion and with respect to the financial risk associated with the energy difference between average and critical water, for reliability purposes, the system plan must be based on critical water (BC Hydro Reply, p. 50).

The issue of the potential impact of climate change on hydrology arose during the proceeding. SCCBC submits that BC Hydro should adopt a more structured and focused approach to research on the potential effects of climate change on its hydroelectric resources (SCCBC Argument, p. 26).

BC Hydro submits that it monitors climate change science and the potential for impacts on its hydroelectric resources, observes the research and activities of other utilities, and engages actively in climate change research (BC Hydro Argument, pp. 64-65). More specifically, BC Hydro testified that over the next four years it was participating in studies that make use of improved modeling capabilities to determine whether climate change will impact B.C. watersheds (T14: 2084-85; Exhibit B-83).

BC Hydro submits that it cannot justify the high cost of additional studies to its ratepayers and shareholder (BC Hydro Reply, p. 58).

Commission Determination

The Commission Panel concludes that BC Hydro should continue to assess the potential effects of climate change on its hydroelectric resources and that in addition to the activities it is currently involved in, BC Hydro should conduct statistical analyses of snow pack, annual precipitation and stream flows, freshet timing and other relevant variables and survey the relevant literature on an ongoing basis for relevant regional trends, with a view to assessing the impact on stream flows and on its major reservoirs. **The Commission Panel directs BC Hydro to file a report with the Commission in its next IEP, identifying significant trends in the literature and summarizing the results of its statistical analyses of historical streamflows.**

The Commission Panel observes that the early period of the water record significantly reduces the firm energy capability of the Heritage hydroelectric system and encourages BC Hydro to continually assess the likelihood of a re-occurrence of water flows similar to the water flows in the critical period, with the objective of reducing the period of record if appropriate to do so.

The Commission Panel acknowledges that the capability of the Heritage hydroelectric system is approximately 3,900 GW.h greater under average water conditions than under critical water conditions. The Commission Panel notes that under its energy planning criterion, BC Hydro must plan sufficient firm supply to meet energy demands in each and every year, even under critical water conditions. However, the Commission Panel also encourages BC Hydro to continue to explore alternative strategies for firming the Heritage hydroelectric resources available to meet demand in critical water years.

3.2.1.2 Reliance on 2,500 GW.h/yr of Non-Firm / Market Resources

BC Hydro states that traditionally it has met its probable energy forecast with:

- firm energy from BC Hydro hydroelectric resources and thermal resources;
- firm energy contracted from IPPs; and
- up to 2,500 GW.h/yr of non-firm energy/market allowance.

(Exhibit B-6-1, BCUC 1.9.2)

BC Hydro further stated that it evaluated the inclusion of the 2,500 GW.h non-firm energy/market reliance in the 2006 IEP from an economic perspective with the resulting strategy in the LTAP being to minimize planned exposure to high and volatile market prices for natural gas and electricity. BC Hydro states that it has since retested this strategy through a sensitivity analysis based upon the F2006 Call price discovery and updated natural gas and electricity prices and that based on this analysis and the Commission's F2006 Call For Tenders Decision it has modified its plan to rely upon 2,500 GW.h non-firm energy in its supply stack based upon the price certainty that 2,500 GW.h of non-firm energy acquired through calls offers (Exhibit B-17, BCUC 4.430.5.4, pp. 11-12).

BC Hydro testified that it first used the reliance on 2,500 GW.h of non-firm or external market resources in 1995 (T10:1461-62) and that it now proposes to rely on up to 2,500 GW.h of non-firm energy from domestic resources, including non-firm energy from the F2006 and later Calls, to meet its energy planning criterion (Exhibit B-55, Table 8-2; T10:1442-1443). BC Hydro submits that 2,500 GW.h is the maximum amount of non-firm energy that should be relied upon from a reliability perspective (BC Hydro Argument, p.32).

CEC agrees with reliance on 2,500 GW.h of non-firm domestic energy (CEC Argument, p. 20). The JIESC believes that it is appropriate for BC Hydro to continue to rely on 2,500 GW.h of non-firm market energy and states that, as BC Hydro gets closer to self-sufficiency and to a higher ratio of fixed price to market priced supply, reliance on the 2,500 GW.h of non-firm energy can and should be reviewed (JIESC Argument, p. 8).

With respect to the reliance on 2,500 GW.h of non-firm resources to meet demand, BCOAPO submits that an alternative path needs to be examined that results in BC Hydro regaining some of its lost system flexibility arising from accepting any and all IPP energy as and when it arrives which reduces BC Hydro's ability to bridge high price market events from a domestic perspective, and has diminished trade income from Powerex's perspective (BCOAPO Argument, para. 51).

Commission Determination

The Commission Panel accepts BC Hydro's reliance on 2,500 GW.h/ yr for the purposes of the current LTAP, but considers that BC Hydro's decision to amend its policy to rely on domestic non-firm sources only, rather than on a mix of sources, remains an open issue which it expects BC Hydro to address in its next LTAP and in any approvals of acquisitions for non-firm energy in the 2007 Call.

3.2.1.3 System Capacity

BC Hydro states that its generation capacity reliability criterion is designed to ensure that there is sufficient installed generation capacity to reliably serve the instantaneous peak demand of the system.

For its evaluation of capacity reliability, BC Hydro applies a standard Loss of Load Probability ("LOLP") methodology, which assesses the probability of simultaneous outages of generating units creating a shortfall of supply capacity to meet demand in any hour over the year. BC Hydro defines an "adequate" generation system as one that has an annual expectation of being unable to serve the daily peak demand of less than one day in ten years. BC Hydro states that the one day in ten years LOLP methodology has widespread use in the industry. Resource availability is an important aspect of the LOLP methodology, and BC Hydro uses dependable capacity to define the resource availability for its hydroelectric facilities and thermal plants. Dependable capacity, measured in MW, is the amount that resources are capable of supplying to meet the instantaneous peak load for electricity with a high level of confidence. For its system as a whole, BC Hydro calculates that the one day in ten years criterion requires installed dependable capacity to exceed peak load by approximately 14 percent (Exhibit B-1A, p. 2-23).

BC Hydro submitted a loss of load analysis for the study year ending September 30, 2007 in which the monthly load carrying capability of the system is compared with each month's in-service capacity to produce the system reserve percentage. The system reserve percentage for December 2006 (BC Hydro's peak month) is 13.8 percent. BC Hydro calculates the annual risk to be 0.9994, which it states approximates one day in 10 years (Exhibit B-6-1, BCUC 1.22.1).

BC Hydro provides a calculation (based on F2009) that demonstrates how the MWs of reserves are calculated by multiplying the planning reserve margin (14 percent) by the total supply requiring reserves and further reducing the reserves by the reliance on the market (400 MW). BC Hydro states that since both Alcan and the Canadian Entitlement supply their own reserves they can be subtracted from the total supply to determine total supply requiring reserves. The following calculation demonstrates how the MWs of reserves are calculated.

Reserves = 0.14 × (Total Supply – Alcan Supply – CE Supply) – Reliance on Market
= 0.14 × (11,718 – 147 – 0) – 400
= 1,220 MW
where:

Total Supply = F2009 Dependable Capacity Supply (11, 718 MW)
Alcan Supply = F2009 Dependable Capacity Supply (147 MW)
CE Supply = F2009 CE Supply (0 MW)
Reliance on Market = 400 MW.

(Exhibit B-10, BCOAPO 1.31.1)

BC Hydro discussed its 400 MW reliance on the market. It stated that it currently does not have any planning reserve sharing agreements with neighbouring control areas and that the origin of the 400 MW reliance was a capacity sharing agreement with TransAlta that was in place from the mid 1980s to the mid 1990s which was terminated when Alberta's electricity market was restructured. BC Hydro states that although the agreement is no longer in effect, the probability is that the surplus capacity continues to exist on the Alberta system and that, while the Alberta-B.C. intertie is currently often derated due to transfer capability limitations within the Alberta integrated electricity system, it continues to include the 400 MW of dependable capacity reliance on neighbouring utilities as resource capacity still exists on the Alberta system and because BC Hydro is interconnected to the U.S. BC Hydro stated that it would need to arrange for and acquire electricity from other jurisdictions if generation on BC Hydro's system was not available and that there are various commercial or operational alternatives available for such acquisitions (Exhibit B-6, BCUC 1.22.2).

BC Hydro stated that transmission restrictions within Alberta have caused transmission from Alberta to B.C. to be currently constrained such that there is generally no capacity except from 1 a.m. to 5 a.m. daily (Exhibit B-6, BCUC 1.3.2) and that, due to the complexities in operating the system and the mix of available resources to meet peak load, it does not explicitly call upon the 400 MW external reliance (Exhibit B-10, BCUC 2.315.2).

Commission Determination

The Commission Panel agrees with the overall evaluation of the capacity reserve margin using the one day in ten year LOLP methodology. However, the Commission Panel has the following reservations about its application and directs BC Hydro to address them in its upcoming LTAP.

Although BC Hydro states that the criterion requires the installed capacity to exceed peak load by a probabilistic factor it calculates to be 14 percent, the planning reserve margin appears to be calculated based on installed capacity and as a result remains essentially constant as peak demand increases, or in fact decreases when Burrard is eliminated. The Commission Panel finds this characterization of reserves confusing and expects that reserves should be more directly relate to peak demand for the purposes of presenting BC Hydro's load/resource balance. **The Commission Panel notes that in different versions of the load/resource balance BC Hydro has included a line item for "additional reserves" but this line item is found in a different location and does nothing to aid understanding of the load/resource balance. The Commission Panel directs BC Hydro to address this apparent anomaly in its next LTAP.**

In considering BC Hydro's reliance on 400 MW from neighbouring jurisdictions the Commission Panel finds that no contract exists which might persuade it that the 400 MW would be available from either of the neighbouring jurisdictions to BC Hydro with a high level of confidence to meet its peak load. Nevertheless the Commission Panel accepts that the 400 MW is effectively backstopped by the availability of the CE, as set forth in Section 3.2.2 of this Decision, and thus can be considered as dependable capacity for planning purposes. However, the Commission Panel also notes that in the near-term BC Hydro also relies on the CE for additional capacity in addition to the capacity provided by reserve sharing. **Given transmission constraints noted by BC Hydro, the Commission Panel is concerned that BC Hydro is overestimating the available capacity from reserve sharing and the CE. The Commission Panel directs BC Hydro to address this issue in its next LTAP.**

3.2.1.4 Evaluation of Wind Resources

The exploitation of wind resources is an important component of BC Hydro's resource plans. Wind resources are being acquired as a result of the F2006 Call and are expected to be bid into the 2007 Call, and are included in BC Hydro's CRPs (Exhibit B-55, Appendix O, Tables 7, 8, 9).

BC Hydro submits that although there is good wind potential in British Columbia, there may be a limit to the amount of wind resources that BC Hydro's system can absorb, and observes that other jurisdictions have capped the volume of wind to 10 percent of the system capacity (BC Hydro Reply, p. 21). BC Hydro describes that any flexibility of the existing system that is used to absorb non-firm and/or intermittent resources is flexibility that cannot be used for purchasing low-cost market resources and increase the complexity of dispatching generation and the need for regulating resources (BC Hydro Argument, pp. 95-96). BC Hydro claims that a comprehensive quantitative wind study may not be possible before the 2007 Call, and promotes the adoption of conservative assumptions for wind acquisitions (BC Hydro Reply, pp. 21-22).

In response to requests from wind developers, BC Hydro conducted a study to determine the ELCC of 1,000 MW of incremental new wind capacity. The ELCC method for evaluating wind capacity uses a probabilistic approach that is sensitive to wind availability, rather than relying on a deterministic value for available capacity. While this method can account for the combined contribution of a number of projects, BC Hydro acknowledged that the current ELCC models are not capable of modeling correlations between wind sites and may tend to overestimate the ELCC, especially if the multiple sites share similar conditions, and in the absence of good data, may not provide more accurate results than deterministic methods (Exhibit B-10, SCCBC 1.32.3). The results of BC Hydro's ELCC study showed that on-shore wind resources had an ELCC of 21 percent as compared to a dependable capacity rating of 5 to 10 percent, and off-shore resources had an ELCC of 29 percent as compared to a dependable capacity of 12 percent (Exhibit B-1B, Appendix F, p. 3-2, Table 3-1). BC Hydro has elected to use the ELCC rather than the dependable capacity for the purposes of assigning a firm capacity value to wind resources (Exhibit B-6, BCUC 1.179.1).

SCCBC filed a study entitled "*Determining the Capacity Value of Wind: A survey of methods and implementation*" where the methodology for calculating wind capacity credit was described for thirteen jurisdictions. Six of the jurisdictions appeared to base the wind capacity credit on some form of measured data (Pennsylvania-New Jersey-Maryland Regional Transmission Organization, New York ISO, Southwest Power Pool, Electric Reliability Council of Texas ("ERCOT"), Mid-Continent Area Power Pool, and Idaho Power). The remaining seven jurisdictions used some form of ELCC modeling or an assumed value for the wind capacity credit. Of the six jurisdictions that used some form of measured data, the wind capacity credit that was actually being utilized was reported for three jurisdictions, and in each of those jurisdictions (Southwest Power Pool, Electric Reliability Council of Texas, and Idaho Power), the wind capacity credit was uniformly lower than the ELCC or wind capacity used by the seven jurisdictions relying upon ELCC modeling or an assumed value.

For the wind plants studied in the Southwest Power Pool region, the capacity values ranged from 3 percent to 8 percent of rated capacity. For ERCOT, although the average output of the wind plants during the defined measuring period was 16.8 percent of rated capacity, the ERCOT Generation Adequacy Group is considering a recommendation to use 2 percent of rated wind capacity as the capacity value because of the confidence factor associated with the variability of wind generation (Exhibit C25-17, Attachment 1).

The IPPBC looks at the issue from another perspective and states: "…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" (Exhibit C18-5, para. 55).

An IPPBC witness testified on aggregation of risk:

> "What we mean by that is that there may in fact be no net cost to B.C. Hydro because B.C. Hydro benefits from the aggregation of all of these different projects, northeast wind, and southwest hydro and the gains in one may be offset by the losses in another. It's a well-known fact that when you start combining a whole bunch of variables, each one has a wide range of variability. The combined total of them is a much narrower range. Okay? And much more likely to be manageable" (T23:3642-43).

BC Hydro submits that it does not agree with IPPBC's proposal and that it would require a significant amount of hydrology and wind data to establish to its satisfaction that the firm portion of energy tendered for an intermittent resource was indeed physically firm (BC Hydro Reply, pp. 98-99).

Commission Determination

The Commission Panel understands IPPBC's testimony on aggregation of risk to refer to portfolio management theory which is an accepted theory in corporate finance circles but which, in the Commission Panel's opinion, may not be as readily applied to a portfolio of intermittent resources. However, in light of expected government policy direction on this issue, the Commission Panel will not make a determination concerning the aggregation of intermittent resources. **The Commission Panel expects BC Hydro to consider the issue of the effects of aggregating intermittent resources on dependable capacity within the 2007 Call and in its next IEP.**

The Commission Panel is concerned that BC Hydro may be overstating the dependable capacity of future intermittent resources and directs it to continue to carry out hydrological and wind studies that may inform its estimates of dependable capacity for existing and future intermittent resources in its next call and IEP.

3.2.2 Canadian Entitlement

BC Hydro states that the CE arises under the Columbia River Treaty and comprises half of the additional electricity potential in the U.S. projects on the Columbia River as a result of the construction and operation of the Canadian Treaty dams namely Duncan dam, Hugh Keenleyside (also called Arrow) dam and Mica dam which regulate river flows, providing downstream flood protection and increasing the generation capability at projects on the U.S. portion of the Columbia River (Exhibit B-1B, Appendix F, p. 7-49).

Under an agreement effective April 1, 1999, and ending on September 15, 2024 (the earliest date the Treaty may be terminated) the Province assigned to Powerex its right, title and interest in the CE, for which it receives each month payment based on the Mid-C price.

BC Hydro states that the amount of the CE is based on a calculation prepared annually and that currently the CEs are forecast to provide approximately 1,200 MW of dependable capacity and 4,200 GW.h of energy per year. BC Hydro expects that the amount of capacity available will remain in the range of 1,000MW to 1,400 MW throughout the period until 2024.

BC Hydro states that the CE is available for it to purchase at market value but, because the CE is a low capacity factor resource (a low amount of energy relative to the available capacity), Powerex generally schedules it into heavy load hours ("HLH") to maximize its value and that conversely, BC Hydro's energy purchases for domestic use tend to be concentrated into light load hours ("LLH") to minimize purchase costs, with the result that BC Hydro tends to utilize the CE only to augment its capacity supply rather than as a source of energy supply.

BC Hydro states that the Columbia River Treaty requires the U.S. to deliver the CE, net of transmission losses to the Canadian border near Oliver or at such other places as the entities may agree upon and the parties have agreed to deliver the CE to existing points of interconnection at Blaine and Nelway and to apply transmission losses of 3.4 percent for energy and 1.9 percent for capacity. The Entity Agreements associated with the Columbia River Treaty state that deliveries of the CE "shall not be interrupted or curtailed except for reasons of uncontrollable force or maintenance and then only on the same basis as deliveries of firm power from the Federal Columbia River Power System to Pacific Northwest customers of Bonneville" (a reference to the Bonneville Power Administration or any successor).

BC Hydro does not believe there is any uncertainty with respect to the legal or regulatory regime applicable to the CE (Exhibit B-6, BCUC 1.276.1).

BC Hydro states that the market price of the CE energy is greater than other market opportunities that BC Hydro would expect to be able to purchase and that the CE is a "capacity rich" resource; therefore the market value is based on HLH prices, which are higher than prices for flat or LLH energy. However, the capacity associated with the CE is available to BC Hydro because the CEs are returned to the province at the US-Canada border and it can obtain the CE by requesting that

Powerex not commit to export energy at the time the capacity is required on the BC Hydro system. BC Hydro states that it used this flexibility over the winter peak in January 2004 (Exhibit B-1B, Appendix F, p. 7-49). BC Hydro estimates the current value of the CE capacity to be $10/kW/yr (Exhibit B-1B, Appendix F, p. 7-60).

From a policy perspective, BC Hydro testified that its use of the CE is as a contingency resource to meet short-term operational issues and that it does not plan for the use of the CE in the long-term perspective, but rather keeps it available for short-term utilization as a capacity resource (T8:1056-58) and that the CE then becomes a short-term resource available over a longer time-frame, which can be used for addressing contingencies (T8:1064).

BC Hydro confirmed that marketing of the CE will be coordinated with Powerex such that the CE is only marketed on a short-term basis, thereby allowing the CE to be reserved for BC Hydro's contingency plans (Exhibit B-6, BCUC 1.1.2, p. 5; T8:1053).

BC Hydro submits that although CE could be used as an energy resource to firm up water variability, this would undervalue the CE because it is more valuable as a capacity resource by being able to be shaped in heavy load or super-peak periods (BC Hydro Argument, pp. 118-19).

In respect of its reliance on up to 400 MW of firm capacity from neighbouring control areas for satisfying the capacity reserve margin BC Hydro testified that in situations where CE supply was being relied upon, the 400 MW from neighbouring control areas could be difficult to access because of transmission constraints. Specifically, in response to questions from the Chair, BC Hydro responded that "… once you start moving into using DSBs, I think you take away that 400 megawatt market reliance because the transmission constraints, you're going to have difficulty getting it there" (T22:3430), and "but practically speaking, what they're doing when they run short of capacity is, as opposed to procuring it at a penalty in the market, they are looking to DSB. So practically speaking, we are firming that with DSBs" (T22:3431).

The JIESC notes that, along with Burrard, the CE represents a large amount of contingency flexibility, and its use would have to be re-examined if it came to be considered a firm resource (JIESC Argument, p. 21).

CEC observes that the CE could be used to firm up the variability over time of the water flows, and thereby create a statistically dependable resource over the long-term (CEC Argument, p. 21).

BC Hydro reiterates that this would not be an effective or efficient use of the CE, and would contravene BC Hydro's generation energy reliability criterion (BC Hydro Reply, p. 50).

Commission Determination

The Commission Panel finds that the CE may provide dependable capacity for BC Hydro for both planning and operational purposes and that the volume of dependable capacity that the CE provides would appear to depend on the availability of transmission capacity between British Columbia and the United States. **The Commission Panel directs BC Hydro to file a study in the next LTAP that identifies the level of firm transmission capacity available to deliver the CE to British Columbia from the United States**.

The Commission Panel notes that a considerable amount of discussion occurred over both the use of CE as a firm resource and the amount of energy from the Heritage hydroelectric system that is available for reliability planning purposes as defined by the critical water period. The Commission Panel accepts BC Hydro's position that using the CE as a resource to firm up energy available under average water conditions is not an economically effective or efficient use of the CE. However, the Commission Panel considers a prolonged period of critical water flows to be an event for which BC Hydro could develop contingency plans, one of which might include the use of the CE as a contingency resource and expects BC Hydro to address this in its next IEP.

3.2.3 Heritage Thermal System

BC Hydro described its Heritage thermal assets as comprising three generating stations, the most significant of which is the 917 MW Burrard Thermal Generating Station ("Burrard" or "BTGS") located on the north shore of Burrard Inlet and whose six 150 MW units were commissioned in the years 1962, 1963, 1966, 1967, 1969 and 1976 respectively. Burrard's natural gas is supplied through a 20-inch main from the gas distribution system (Exhibit B-10, IPPBC 1.11.3, Attachment 1).

BC Hydro stated that Units 1, 2 and 3 were converted to synchronous condensers by the decoupling of their generators from their turbines while Units 4, 5 and 6 remained operational and that in the winter of 2006 Unit 1 was re-commissioned and is now operational. So far as environmental controls are concerned, BC Hydro states that starting in mid-1995 and through 2000, Selective Catalytic Reduction ("SCR") systems were installed on each of the 6 units to assist with the Nitrogen Oxide ("NOx") control strategy at Burrard and that a Continuous Emission Monitoring System ("CEMS") at BTGS samples and analyzes the flue gas from each of the boiler stacks and generates reports to evaluate compliance with the Greater Vancouver Regional District's ("GVRD") air emissions permit.

In a report to BC Hydro dated May 2006 AMEC Americas Limited ("AMEC") stated that the general condition of the plant was very good and that it had been consistently maintained at a high level over its life during which time it had not accumulated extensive operating hours due to its light loading and partial conversion to synchronous condenser operation, with only the generators operating. AMEC also found that the basic plant operating and control facilities had been upgraded over time to contemporary standards with the result that the plant had never failed to start when requested and no start failures were shown in its operating history (Exhibit B-10, IPPBC 1.11.3, Attachment 1, pp.18-23).

BC Hydro stated that Burrard utilizes older, conventional steam technology fuelled by natural gas and is not as efficient as modern gas-fired plants and that its low-efficiency, along with current and forecast higher costs of natural gas, causes it to be largely uneconomic relative to electricity market purchases and that as a result, the plant is dispatched infrequently. Current expenditures are based on the assumption that Burrard must provide dependable capacity, firm energy and voltage support until the end of F2014. Currently, the six units at Burrard are depended upon for the following services:

Capacity:

BC Hydro states that all six units are being relied upon for capacity planning purposes, and three of the six are currently being relied upon for operating purposes. Units 1, 4, 5 and 6 are available to generate electricity, as and when required; while Units 2 and 3 are available to generate electricity on notice ranging from four weeks to two years and will be relied upon for capacity planning purposes beginning in F2009 until F2014. BC Hydro originally stated that it does not currently nominate Burrard's capacity as a Reliability Must Run ("RMR") plant for transmission purposes (Exhibit B-1A, p. 7-50), but now submits that it has no option other than to allow Burrard to be used for RMR purposes until the proposed Interior to Lower Mainland Transmission Reinforcement Project ("ILM") is in service (BC Hydro Argument, p. 105).

Energy:

BC Hydro states that all six units are considered capable of providing energy for planning purposes from F2009 to F2014 with a combined capability to provide up to 6,100 GW.h/yr. However, there is a low likelihood of running the plant for significant energy supply in the near future because of the high cost of natural gas and the station's heat rate (which BC Hydro places in the 10.5-13.0 GJ/MW.h range) (Exhibit B-10, BCUC 2.322.1). The combination of these two factors generally makes it more cost-effective to purchase energy from the market when and as required, while using Burrard as backup in case market energy becomes unavailable or too expensive.

Voltage Support:

> BC Hydro states that Burrard's generators are counted upon for a minimum of two units to provide reactive power (voltage) support. The generators on Units 1 through 4 either are, or can be, decoupled from the turbines and be operated as synchronous condensers. In this mode, a generator provides reactive power (voltage) support without consuming natural gas. The generators of Units 5 and 6 have not been refitted to be able to be decoupled from the turbines to operate as synchronous condensers and, therefore, can not used to provide this function (Exhibit B-1A, pp.7-27, 7-29).
>
> BC Hydro estimates that it would cost $76 million to install new static VAr compensators and a transformer to perform the voltage control function currently being performed by Burrard (Exhibit B-86).

BC Hydro states that since gas and electricity price forecasts have continued to show increases in price, the status of Burrard has changed and it is now expected to be less economic as a result of increasing natural gas prices and increasing risks associated with continued operation which combine to make Burrard a increasingly costly and risky resource to rely upon to provide stable-priced reliable electricity supply (Exhibit B-6, BCUC 1.286.1).

BC Hydro states that it has assessed the liquidity of the current Huntingdon/Sumas spot natural gas market as well as the un-contracted firm space on the Duke/Westcoast pipeline which provides the opportunity to access both the Station 2 and Sumas natural gas markets, and that based on this assessment, the supply of natural gas is sufficient to not materially reduce the effectiveness of the physical capability of Burrard for the situation of running three units. BC Hydro states that it will re-assess the situation with respect to physical access to gas supplies when further units are required for dependable capacity and firm energy and that the outcome of future re-assessments could range from possible commitments to longer term gas supplies or options to call on gas supply during peak periods to remaining with short term spot market arrangements (Exhibit B-10, BCUC 2.340.1).

BC Hydro cites the AMEC report which concludes that at current maintenance levels the existing six units are capable of operating at a reduced level of 400 GW.h/yr until 2024, with a worst case scenario of all units operating at a reduced level until 2021 after which three units could operate at the same reduced level until 2024 by shutting down the worst performing units and using them for spare parts to support the units remaining in operation. AMEC suggests that for an annual output exceeding 200 GW.h/yr, more sensitivity analysis into potential cost increases at Burrard should be performed, however annual output in any given year of 400 GW.h up to 2024 should be possible without materially affecting the results reported in the study. AMEC was not asked to assess the costs of increasing availability beyond 400 GW.h/yr (Exhibit B-10, IPPBC 1.11.3, Attachment 1, pp. 1-3).

BC Hydro submits that only through its concerted effort has it been able to continue to operate Burrard and maintain its “tenuous social license”, and that it plans to discontinue relying upon Burrard for planning purposes, that is, for dependable capacity and firm energy at the end of F2014 (BC Hydro Argument, p. 104).

BC Hydro submits that its plans to discontinue relying upon Burrard for planning purposes are based on the earliest date that the services it provides to the system can be replaced. If these services are not replaced by the end of F2104, then BC Hydro plans to keep Burrard operating until such time as they are, and that by planning to discontinue relying on Burrard for planning purposes after F2014, BC Hydro is not suggesting that the plant will not be available for operation after F2014, and states that “In fact, the simple probability is that it will” (BC Hydro Argument, pp. 104-05).

BCOAPO observes that Burrard is ideally situated for proximity to the load and the necessary pipeline and transmission facilities, and submits that unless IPP developers dramatically improve their ability to bring projects in on time, Burrard’s useful life will continue beyond F2014 (BCOAPO Argument, paras. 105-107).

CEC submits there is no choice for BC Hydro but to plan at some time to cease relying on Burrard and that the Burrard plant can and should have a role after F2014 as a contingency resource option for some time. CEC submits that the useful life of Burrard should be considered to continue so long as there is any appropriate role remaining for the plant, including a back-up insurance role where the plant may require a year or more to be made ready to serve its purpose (CEC Argument, pp. 50-51).

The JIESC strongly supports the plans of BC Hydro to maintain Burrard in an operational state for as long as it is cost-effective to do so, and to maintain the potential for Burrard repowering for now, but not to take further action on Burrard repowering at this time (JIESC Argument, p. 15).

IPPBC agrees with BC Hydro's assessment that the current Burrard plant "should be viewed as a capacity resource and that it is masking energy market purchases" and argues new domestic sources of energy must be brought on line to reduce the risk associated with these market purchases (IPPBC Argument, p. 17)

SCCBC supports BC Hydro's decision to discontinue relying, for planning purposes only, on Burrard at the end of F2014 (SCCBC, Argument, p. 21).

Terasen agrees with BC Hydro's treatment of Burrard as a supply resource, and supports BC Hydro's approach to maintaining Burrard as a flexible contingency resource to mitigate any risks to the in-service timing of ILM, and recognizes that as a result Burrard may continue to be required beyond 2014 (Terasen Argument, paras. 8-9).

Terasen also commented on the Throne Speech phrase that "[a]ll new and existing electricity produced in B.C. will be required to have net zero greenhouse gas emissions by 2016" and observed that future carbon credit and carbon offset may offer alternatives to decommissioning Burrard (Terasen Argument, para. 10).

Commission Determination

The Commission Panel observes that although BC Hydro plans to discontinue relying on Burrard for planning purposes after F2014, the plant will continue to be operational for some time after. The Commission Panel also observes that BC Hydro sought no explicit determinations in the Application with respect to Burrard. **Therefore, the Commission Panel rejects BC Hydro's assumption that Burrard will have no contribution to dependable capacity or firm energy beyond F2014.** Until a formal request by BC Hydro, the Commission Panel considers the future contribution of Burrard is uncertain. This uncertainty will need to be resolved by BC Hydro in order to support the timing and volume of future calls and to establish the need for any EPA's awarded under those calls. The Commission Panel expects this uncertainty to be resolved by BC Hydro's next IEP.

3.2.4 Demand Side Management

BC Hydro's existing DSM programs are known as Energy Efficiency 2 ("EE2") and Load Displacement 2 ("LD2"). EE2 is built around opportunities for energy savings identified in BC Hydro's 2002 CPR. BC Hydro states it is a low cost resource which has consistently delivered targeted electricity savings within planned costs. In the period from April 2001 to December 2005 the EE2 portfolio has achieved an All Ratepayers Test (also known as the Total Resource Cost Test) benefit/cost ratio of 1.7 (Exhibit B-1E, p. 8-16).

LD 2 consists of three existing contracts with three separate industrial customers. The only future load displacement project within the LD2 umbrella is the Greater Vancouver Water district micro-hydro Load Displacement Project (Exhibit B-1E, p. 8-16).

For the purpose of calculating the difference between supply and demand, BC Hydro states that EE2 and LD2 will contribute 2,700 GW.h by F2012 (the end of the program) falling to 2,400 GW.h by F2025 (Exhibit B-1E, p. 8-11).

No Intervenor took a position with respect to the level of energy savings forecast by BC Hydro with respect to EE2 and LD2, except the JIESC, which accepts the estimates as "… sufficiently accurate for the purposes of this proceeding."

Commission Determination

The Commission Panel has expressed concerns with the methodology used to forecast and monitor DSM savings, as discussed in Section 6 of this Decision. However, at this time, for planning purposes, the Panel accepts BC Hydro's forecast as to the quantity of energy supplied by EE2 and LD2 and available to close the resource gap.

3.2.5 Existing Purchase Contracts

In its 2006 IEP Integrated System Firm Energy Load Resource Balance, BC Hydro sources energy from:

- existing purchase contracts; and
- F2006 Call, Firm and Non-firm Energy.

(Exhibit B-44, p. 6)

Existing Purchase Contracts

BC Hydro states that existing purchase contracts refer to IPP contracts signed before the F2006 Call that are both delivering energy and those not yet in service, and that it has adjusted the expected contract volumes to reflect attrition. Of contracts issued for 1,732 GW.h/yr it expects to receive 1,051 GW.h/yr after F2010 (Exhibit B-17, BCUC 4.431.1 and 1.1). This assessment is based on an ongoing assessment of project development. BC Hydro testified that of the 16 EPAs issued in the 2003 Green Call, only two are delivering energy of 40 GW.h/yr (T8:925).

F2006 Call

BC Hydro states that it issued 38 EPAs for a total of 5,721 GW.h/yr of firm energy and 1,400 GW.h/yr of non-firm energy, to which it applied an attrition allowance of 23 percent and an outage allowance of 7 percent to arrive at forecast deliveries from the F2006 Call of 4,000 GW.h/yr firm and 1,000 GW.h/yr non-firm (Exhibit B-44, p. 7). To the firm quantity it added 200 GW.h/yr from the Brilliant Expansion Project. BC Hydro files a report prepared for the California Energy Commission entitled "Building a margin of safety into renewable energy procurements – a review of experience with contract failure." This document states that "the data suggest that a minimum overall contract failure of 20 to 30 percent should generally be expected for large solicitations conducted over multiple years" (Exhibit B-112, Abstract).

BC Hydro submits that its attrition rate of 23 percent was based on an internal analysis, which identified an expected range of attribution based on the terms of the Call and underlying EPAs (BC Hydro Argument, pp. 58-59).

Intervenors do not challenge the BC Hydro assessment. The CEC submits that BC Hydro's estimate is probably inaccurate but that BC Hydro's accuracy cannot be improved at this time (CEC Argument, p. 36).

Certain Intervenors note that the Throne Speech may have made the two coal-fired projects the first objects of attrition (JIESC Argument, p. 11; SCCBC Argument, p. 5; BCOAPO Argument, para.7)

BC Hydro submits that it has clearly met the burden established by the Commission's F2006 Call Decision, where the Commission stated that it "neither accepts nor rejects BC Hydro's argument to increase the award volume to reflect attrition and outage risk, or the specific attrition and outage allowance proposed by BC Hydro." The Commission indicated that it expected the issue to be addressed more explicitly as part of the 2006 IEP/LTAP proceeding. The evidence in the current proceeding and the potential consequences of recent policy developments indicate that BC Hydro's estimates of attrition were reasonable and were not seriously challenged by any party (BC Hydro Reply, p. 50).

On the matter of whether the two coal-fired generation projects from the F2006 Call have an increased likelihood of attrition in light of recent policy developments, BC Hydro submits it is still too early to draw any firm conclusions about the prospects for these projects, but concedes that "they now face some additional challenges in light of the Throne Speech pronouncements" (BC Hydro Reply, pp. 50-51).

Commission Determination

The Commission Panel accepts BC Hydro's estimate of an attrition and outage allowance of 30 percent in respect of the F2006 Call as a valid assessment of the potential attrition and outage rate, at the time it was made. The Commission Panel also accepts that the estimate will change as the 38 projects proceed through their various phases of development.

The Commission Panel's finding with respect to the attrition rate of future calls are set out in Section 6.2 of this Decision.

3.3 The Load/Resource Balance

BC Hydro states:

> "A major component of the 2006 IEP process…is determining the load resource balance. Simply put, when the load resource balance (available resources minus load) turns negative a gap exists between the customer demand forecast to be served and the supply available to serve such demand. This "gap" is the starting point for defining *how much* will be required and *when* to acquire new resources" (Exhibit B-1A, p. 4-1).

The load/resource balance reflects the load forecast and projected/committed resources discussed above, and it takes into account two reliability requirements - energy and capacity. BC Hydro's original load/resource balance is presented in detail in Tables 4-9 and 4-10 of the Application (Exhibit B-1A, pp. 4-43 to 4-44). An amended load/resource balance was filed by BC Hydro on August 31, 2006 as part of its amended LTAP (Exhibit B-1E). In the response to BCUC 4.430.5.4 (Exhibit B-17-3), BC Hydro provided an updated energy load/resource balance table for the period of F2006 to F2015 reflecting the addition of domestic non-firm supply from the F2006 Call, the impact of the Commission's decision regarding the LTEPA+ with Alcan, and the proposed 2007 Call (Amended Tables 4-9 and 4-10, Exhibit B-44).

The amended load/resource balance in Exhibit B-44 indicated that during the operating timeframe of F2006 through F2008 and under the Mid-Load Forecast, BC Hydro is at or near a balance with respect to energy, but has a capacity shortfall of 300 to 500 MW before reliance on CE because at least two of the Burrard units have been disconnected from the grid during this period (Exhibit B-44, pp. 4-5). After taking into account anticipated supply from DSM and the F2006 Call, BC Hydro projected the capacity deficit grows from 200 MW in F2009 to 1,400 MW in F2015, before any contribution from the CE. The deficit in F2015 reflects in part BC Hydro's elimination of Burrard from the resource stack in F2014.

In Response to an Undertaking for the Commission Panel (T10: 1469), BC Hydro provided an update of Chapter 8 of the 2006 IEP/LTAP to reflect the 2,500 GW.h of non-firm energy allowance as indicated in BCUC 4.430.5.4, Exhibit B-17-3 (Exhibit B-55). The reflection of the 2,500 GW.h of non-firm energy would result in a deferral of the need for the 2009 Call from F2015 to F2018. With the 3-year deferral, the next unit at Mica or Revelstoke would need to be advanced from fiscal 2022 to fiscal 2015. The basis for BC Hydro's CRPs did not change, although BC Hydro did update the resource schedules.

Relying on Exhibit B-44, BC Hydro submits that, with the Mid-Load forecast, an energy deficit of 2,400 GW.h will exist in F2009 (the first year of its planning timeframe) and will increase to 9,500 GW.h by F2015. BC Hydro further submits a capacity deficit exists now and steadily grows to a deficit of approximately 1,400 MW by F2015 (BC Hydro Argument, p. 25). Both the energy and capacity gaps reflect BC Hydro’s elimination of 910 MW of capacity and 6,100 GW.h of energy from Burrard from its resource stack in F2015. For the period until F2010, CE is relied upon to achieve capacity balance in amounts varying between 200 MW and 500 MW, in addition to 400 MW of external resources being relied upon for capacity reserve margin. However, BC Hydro also testified that transmission capability to external markets may be constrained to 400 MW during heavy load periods (T22:3427-31). The total amount of capacity reserve margin projected by BC Hydro does not change after F2014 despite continuously increasing demand and supply portfolios.

Commission Determination

The Commission Panel finds BC Hydro’s portrayal of the load/resource balance during this proceeding was inconsistent and confusing. As noted by BC Hydro at the outset, a load/resource balance is required initially to establish need with respect to reliability planning criteria. BC Hydro, however, frequently includes both reliability and economic considerations in its analysis of the load/resource balance. While the Commission Panel agrees economic considerations should form part of the development of the LTAP, the Commission Panel would like to have seen a clearer distinction between reliability requirements and economic considerations in BC Hydro’s analysis of resource needs. For example, BC Hydro’s initial load/resource balance excluded its non-firm/market allowance from the resource stack. However, in response to BCUC 2.302.4 (Exhibit B-10), BC Hydro stated that it is not proposing to alter its energy planning criterion and that the elimination of the 2,500 GW.h non-firm/market allowance was based on an economic evaluation. In response to BCUC 4.430.5.4 (Exhibit B-17), BC Hydro acknowledged that the non-firm resources acquired in the F2006 Call could be included in its load/resource stack as part of the non-firm/market allowance and altered the load/resource balance accordingly. In response to an Undertaking for the Commission Panel (T10: 1469) BC Hydro provided a revised load/resource balance reflecting the effect of the full 2,500 GW.h non-firm/market allowance on its load/resource balance (Exhibit B-55).

Until a decision is made to alter BC Hydro's reliability planning criteria, the Commission Panel considers the entire 2,500 GW.h non-firm/market allowance is available to BC Hydro for reliability planning purposes. Whether this allowance is met through market purchases or long-term contracts for non-firm supply is an economic consideration, which may form part of the LTAP, but this should be clearly identified as an economic substitution of resources rather than a gap that needs to be filled for reliability planning purposes.

BC Hydro has made no request for determinations with respect to Burrard in this proceeding. Since no application has been made or accepted with respect to Burrard, the Commission Panel considers it better to reflect uncertainty over Burrard as a range in the load/resource balance and future resource requirements. The Commission Panel notes that at some point BC Hydro will need to formally resolve this uncertainty in order to guide the timing and volume of additional calls and to establish the need for any EPAs awarded under those calls.

With respect to the capacity load/resource balance, the Commission Panel also finds that BC Hydro's calculation of the future reserve requirements is confusing and inconsistent with its own definition of the reserve margin. Specifically, the reserve margin does not grow with load, as it should, and as a result the capacity required for reliability planning purposes may be understated. The addition of a line item in the load/resource balance under new supply for additional reserves is confusing.

The Commission Panel is also concerned by BC Hydro's combined reliance on both reserve sharing with neighbouring jurisdictions and the CE in certain years, given testimony regarding transmission constraints. The Commission Panel expects these issues to be more clearly addressed and resolved in future IEP/LTAP filings.

The Tables below summarize all of the Commission Panel's findings with respect to the load/resource balance for representative years of F2009 and F2015. These tables are based mainly on Exhibit B-44, with adjustments as follows. The full non-firm/market allowance is included in the energy load/resource balance, as outlined in Exhibit B-55. In addition, a range is shown for Heritage

Thermal to reflect uncertainty over the future role of Burrard. The capacity balance reflects some rounding of the dependable capacity of the various resources. The reserve requirement in the capacity balance is based on Exhibit B-55, and is likely underestimated for the reasons noted above. The capacity balance is summarized before any additional reliance on the CE. The values in the tables below may also vary from those provided by BC Hydro due to differences in rounding.

These tables reflect reliability planning requirements. Additional resources may also be included in the LTAP based on economic considerations, such as substitution of market purchases with non-firm domestic purchases under long-term contracts. However, these substitutions must be justified on economic grounds rather than reliability grounds. These decisions are discussed further in Section 6 of this Decision, which addresses BC Hydro's LTAP.

Given uncertainty over the future of Burrard and the availability of the existing non-firm/ market allowance, the Commission Panel finds there is a critical need for new resources based on reliability planning criteria, but that the magnitude of BC Hydro's long-term need for energy and capacity for reliability planning purposes may be somewhat overstated.

Commission Panel View of Existing Energy Load/Resource Balance

	F2009	**F2015**
Demand before DSM (Mid-Load Forecast)	61,500	67,200
Existing DSM (EE2 and LD)	1,900	2,700
Demand after Existing DSM	59,600	64,500
Existing and Committed New Supply		
Heritage Hydro	42,600	42,600
Heritage Thermal	6,300	200 - 6,300
Resource Smart	300	300
Existing Purchase Contracts	8,000	6,800
F2006 Call Firm Energy (After Attrition Allowance)	0	4,200
Non-Firm / Market Allowance		
F2006 Call Non-Firm Purchases (After Attrition)	100	1,000
Market Allowance	2,400	1,500
Total Supply	59,700	56,600 - 62,700
Energy Load/Resource Surplus (Deficit)	100	(1,800) to (7,900)

Commission Panel View of Existing Capacity Load/Resource Balance

	F2009	**F2015**
Demand before DSM (Mid-Load Forecast)	11,000	11,800
Existing DSM (EE2 and LD)	300	400
Demand after existing DSM	**10,700**	**11,400**
Reserve Requirements (After Sharing and Alcan)*	1,200	1,300
Demand after DSM Plus Reserve Requirements	11,900	12,700
Existing and Committed New Supply		
Heritage Hydro	9,800	9,800
Heritage Thermal**	1,000	0 - 1,000
Resource Smart	0	100
Existing Purchase Contracts	800	700
F2006 Call Firm Energy (After Attrition Allowance)	0	500
Total Supply	11,600	11,100 - 12,100
Capacity Load/Resource Surplus (Deficit) Before CE	(300)	(600) to (1,600)

* Reflects reserve requirements in Exhibit B-44. However, the Commission Panel notes some ambiguity with BC Hydro's forecast of reserve requirements, which it expects to be resolved in the next LTAP / IEP filings.

** Based on BC Hydro's estimate and reflects rounding of Burrard capacity.

4.0 RESOURCE IDENTIFICATION

A key element of the long-term planning process is the identification and evaluation of potential resources. This Section first reviews the ROR in which BC Hydro identified a broad range of potential resources, and then examines BC Hydro's portfolio analysis, which involves the definition and evaluation of resource portfolios consisting of alternative combinations of supply and demand side resources. This Section next considers BC Hydro's assessment of the key categories of resources that can be relied upon to meet long-term needs. Finally, this Section examines the trade-off analysis, which BC Hydro uses to compare the performance of different portfolios across various evaluation attributes and under different scenarios for key uncertainties.

4.1 Resource Options Report

The Commission's Guideline No. 3 reads as follows:

> "Identification of supply and demand resources
>
> Feasible individual supply and demand resources, both committed and potential, should be listed. Individual resources are defined as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand. Feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy."

BC Hydro appends its 2005 ROR to its 2006 IEP/LTAP application as Appendix F (Exhibit B-1B) and states that the 2005 ROR identifies a broad range of resources and technologies that could potentially be used to meet BC Hydro's future electricity demand and that resource options include both supply-side and demand-side options.

BC Hydro states that one of the purposes of the ROR is to describe the characterization of resource options that will be used in the 2005 IEP and that, in characterizing the resource options, its goal was to use current and verified information to provide realistic ranges on volume and cost and to appropriately characterize environmental and social attributes and that ultimately, the information resulting from the ROR and IEP will aid in making decisions about: how to structure competitive acquisition calls (what, when, where, why); what BC Hydro projects should be advanced; and what level of transmission service should be contracted (Exhibit B-1B; Appendix F, p. 1-1).

BC Hydro submits that since the 2002 Energy Plan established that new supply will be provided by the private sector this change in focus means that it must work closely with future energy suppliers to obtain information on resource options that can be used for long-term energy planning and that its data were obtained from a wide range of sources including the IPP developers themselves and that much of the cost-related and other information contained in the 2005 ROR originated with the IPP community (BC Hydro Argument, p. 75).

BC Hydro states that it received these data from a variety of sources and levels of study, that it reviewed the data and compared them with industry standards to provide quality assurance and that it was informed by Commission Order G-96-04 where it stated that the accuracy of cost data for long-term planning purposes may be +/-35 percent for specific projects, and may have confidence levels exceeding this range for resource types without specific project information.

BC Hydro states that one objective of the ROR is to simplify the representation of resource options data and show how the data will be used in portfolios, and that another objective of the portfolio analysis is not to pick individual projects, but to establish a strategy for future resource acquisitions. As a result, BC Hydro states that its approach to the 2005 ROR was to represent the potential of different resource types as generic blocks, which it developed by the use of supply curves and project-specific information for the different resource types.

BC Hydro states that the ROR focuses on resource options that can reasonably be expected to be developed to meet load requirements within the 20-year resource planning time frame and that can be defined as a volume of energy or capacity and associated cost. These include projects that would reasonably be expected to bid into a competitive acquisition call, or be advanced by BC Hydro. Other strategic policies that may influence the future load growth or acquisition outcomes, such as rate options and some other DSM activities are not considered. BC Hydro states that it developed a simple screening process to categorize the projects in the Resource Options database into the following seven categories:

- Imports;
- Backup generation;
- Net metering;
- Near-commercial technology projects;
- DSM;
- Future resource options (projects with unverified resources or a project that is not being actively investigated in B.C.); and
- Generic resource blocks

and that projects in the last group were used to develop the generic blocks for different resource types and these generic blocks and the DSM programs were used in the portfolio analysis of the IEP (Exhibit B-1B, Appendix F, p. 1-6).

DSM

BC Hydro states that its 2005 ROR includes future increments of energy efficiency programs as options that are based on attaining potential savings identified in the 2002 CPR beyond those that have been committed to in the current energy efficiency plan. These three future options are all based on energy-efficient technologies, and are characterized by their expected period of implementation. The sequence of these options is an indicator of increasing levels of cost and challenge to achieve. The future options are as follows:

- Energy Efficiency 3 (“EE3”) – from fiscal 2013 to fiscal 2017;
- Energy Efficiency 4 (“EE4”) – from fiscal 2010 to fiscal 2024; and

- Energy Efficiency 5 (“EE5”) – from fiscal 2008 to fiscal 2024.

Generic Resource Blocks

BC Hydro considers the following generic resources:

- Natural gas - gas turbines in both simple cycle and combined cycle modes and cogeneration projects;
- Coal - both pulverized coal and coal gasification;
- Biomass - wood residue, municipal solid waste and biogas;
- Geothermal;
- Wind both on- and off-shore based on a Garrard Hassan study;
- Small Hydro - run-of-river projects up to 110 MW based on a Knight Piesold database; and
- Large Hydro comprising the Brilliant and Waneta expansions; Resource Smart projects Revelstoke Unit 5 and Unit 6, and Mica Unit 5 and Unit 6; and Site C.

BC Hydro submits that resource options used in the 2006 IEP analysis were those identified in the ROR whose database of resources contained sufficient information on physical, financial, environmental and social characteristics to allow for both economic analysis and social impact analysis.

BC Hydro submits that it recognized that costs had escalated since the time the 2005 ROR was completed and that as part of the 2006 IEP analysis, it completed and filed sensitivity analyses with respect to capital cost escalations to test the relative impact of such escalations on the results of the IEP analysis. However, the fact that construction or capital costs have escalated does not take away from the value of the 2005 ROR in the 2006 IEP planning process or in the value of the 2006 IEP in setting the context for BC Hydro’s LTAP. The 2006 IEP analysis provides a broad contextual backdrop for BC Hydro, its customers and stakeholders to understand and discuss the resource attributes that are important and the relative impacts of such resources on BC Hydro’s system. BC

Hydro submits that all of the plant gate prices paid in the F2006 Call fell within the ranges of the unit energy costs contained in the 2005 ROR.

BC Hydro views the type of stakeholder engagement and the substantive work behind, and the information contained in, the 2005 ROR to be an important input into its planning process. As a result, BC Hydro intends to undertake a similar evaluation in conjunction with the next IEP (BC Hydro Argument, pp. 65-66).

CEC finds the ROR exercise lengthy and full of detail with significant ranges of uncertainty such that the use of the material in planning could only have limited value. CEC believes that BC Hydro may find it useful to keep the ROR exercise in some form so that it has at least an understanding of what is evolving in each of the potential resource areas it may draw on (CEC Argument, p. 6).

The JIESC supports the formal elimination of a separate ROR and its assimilation into the IEP, calling it a positive development in the current IEP that worked well and should be continued. The 2005 ROR and the portfolios analyzed by BC Hydro cover the full range of commercially proven available resources. While they will now need to be updated, and probably expanded, to bring in other resources that are now required the approach is a reasonable one provided the data is used as a guide as to resource availability and not for acquisition decision making (JIESC Argument, pp. 13-14).

IPPBC, on the other hand, is not impressed by the ROR's cost estimates and submits that the cost estimates of the resources that are included in the portfolios are simply not accurate enough to produce any meaningful result and that the range of Site C cost estimates is so broad as to be meaningless and does not take into account recent construction price increases that do not necessarily apply to all types of generation and conservation technology and the risk associated with developing a project with a development timetable exceeding 10 years.

IPPBC submits that the ROR database includes other examples of unit energy costs for other forms of generation technology such as wind coal, biomass, small hydro, natural gas etc. which are equally meaningless and that the results of the F2006 Call confirmed how inaccurate these unit energy costs are and how unsuitable they are for any purpose, including planning (IPPBC Argument, p. 45).

Commission Determination

The Commission Panel concludes that BC Hydro’s 2005 ROR served a useful purpose in the Application and commends BC Hydro’s intention to undertake a similar evaluation in conjunction with its next IEP. So far as the financial characteristics contained in the 2005 ROR are concerned, the Commission Panel finds that their accuracy fell within the parameters which the Commission established in its previous Order No. G-96-04, where it stated at page 63:

> “The Commission Panel does not expect that the determination of “target ranges” will be supported by portfolio analysis; however, preliminary portfolio analysis is not precluded. Moreover, the Commission Panel does not expect that the determination of “target ranges” will be supported with estimates of costs beyond “planning estimates”. Estimates need to be prepared with consideration of the intended use, that is, to support “target ranges”. For specific projects, a suggested confidence range is plus or minus 35 percent. For certain resource types, particularly those that do not include specific projects, planning estimates may have confidence ranges exceeding plus or minus 35 percent.”

4.2 Portfolio Analysis

BC Hydro chose a portfolio analysis to underpin its IEP. A portfolio analysis involves the definition and evaluation of resource portfolios consisting of alternative combinations of supply-side and demand-side resources to meet customers’ electricity needs (Exhibit B-1A, p. 6-1). BC Hydro testified that its Board of Directors has reviewed this type of analysis and is generally comfortable with it (T7:751-52). BC Hydro indicated a portfolio analysis is also consistent with the Commission’s Guidelines and is considered a best practice for IEP or IRP analysis (T16:2437-41).

BC Hydro submits this type of analysis is appropriate for evaluating the impacts of different combinations of resources from a system-wide perspective (BC Hydro Argument, pp. 66-67). BC Hydro also argues that "[n]o evidence was filed during the evidentiary phase of the 2006 IEP/LTAP proceeding that would suggest either (a) that there was either a better alternative to portfolio analysis or (b) that the portfolio analysis did not provide useful planning contextual information" (BC Hydro Argument, p. 67).

The JIESC indicates that it originally felt the IEP had adequately identified and considered feasible resource options but suggests the ROR and Portfolio Analysis will have to be revisited in light of the Throne Speech, which may have altered the availability and cost of some resources. The JIESC recommends this review be done in time for the filing of next LTAP in late 2007 (JIESC Argument, pp. 12-13). The JIESC generally supports the review or use of portfolios to establish the general availability of resources (JIESC Argument, p. 6). However, the JIESC cautions "the IEP and LTAP are not central planning documents directing resource acquisition decisions but rather are an examination of the resources available and approximate costs" (JIESC Argument, p. 13). The JIESC notes that actual costs will become known and actual choices of resources will be made as a result of calls for tenders.

With respect to both the development and evaluation of portfolios, and the portfolio trade-off analysis, CEC submits that the concept of assembling specific lists of projects for portfolios, which are at best proxies for simpler planning scenarios than BC Hydro may actually face, somewhat overdone (CEC Argument, p. 6). CEC suggests the portfolio and trade-off analyses can be improved by "transitioning from the portfolio concept (reminiscent of or a hybrid from the days of integrated resource planning) to one of acquisition process management for getting the most cost-effective results from the various resources streams to which it has access" (CEC Argument, p. 6). CEC provides no description of what is meant by "acquisition process management" but does state that it "anticipates that it will have the opportunity to provide this view and other constructive suggestions to BC Hydro before its next LTAP process and filing and it is in that consultative context that the CEC submits that changes to the IEP and LTAP process should be worked out by BC Hydro" (CEC Argument, p. 7).

IPPBC states it "…does not believe that BCH should be creating an IEP that is based what can generally be described as the 'portfolio approach,' " and suggests "…it would be better to define the attributes of the resources, including conservation, that BCH wishes to acquire e.g. greenhouse gas emissions, local air emissions, transmission impacts, First Nation impacts etc. and acquire the necessary resources through a competitive acquisition process" (IPPBC Argument, p. 45).

BC Hydro submits that "…IPPBC's alternative to portfolio analysis: (1) is too vague to be adopted by the BCUC; (2) is unsupported by any other Intervenor; (3) has not been identified as being adopted by any other utility or regulator; and (4) would necessitate the BCUC amending its own *Resource Planning Guidelines*, without the benefit of submissions from other regulated utilities." BC Hydro submits that IPPBC has not entered any evidence regarding how its proposal would work in practice. BC Hydro suggests that under IPPBC's proposal the choice of attributes would be "tantamount to choosing the mandatory criteria for a competitive call process." BC Hydro suggests it is not clear how it would secure agreement on the attributes of the resources to be acquired, given the divisions within PIEPC on the appropriate attributes. BC Hydro also notes that no other Intervenor supports the IPPBC proposal and "…while most intervenor Arguments were silent on the subject, those that did address it did not support the acquisition of either Resource Smart projects or DSM by way of a competitive process." BC Hydro also notes that portfolio analysis is a "standard feature" of IRPs and a "common practice." Finally, BC Hydro submits that prior to amending the Guidelines, the Commission should consult with other utilities (BC Hydro Reply, p. 60).

Commission Determination

The Commission Panel agrees with BC Hydro that a portfolio analysis is consistent with the Commission's Guidelines, which state: "For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast." The Commission Panel also agrees with BC Hydro that a portfolio analysis is a best practice for IEP or IRP analysis. Finally, the Commission

Panel agrees a portfolio analysis is useful to BC Hydro management, stakeholders and the Commission in reviewing acquisition plans.

The Commission Panel does not have sufficient evidence to evaluate possible alternatives to a portfolio analysis, or to amend the Commission's Guidelines. The Commission Panel acknowledges that a portfolio analysis is not intended to replace a competitive call process. Calls provide valuable information on the relative costs and benefits of resource options that may be developed by the private sector. However, the Commission Panel continues to see a role for portfolio analysis to select among resources to be developed by BC Hydro (e.g., DSM and Resource Smart) and resources to be developed by the private sector. Furthermore, a portfolio analysis is also essential in framing any competitive acquisition process, including the target size and timing of calls, the type(s) of product(s) to be acquired (e.g., the relative value placed on capacity versus energy in a particular call), eligible resources (based on government policy and management decisions arising from a preliminary portfolio analysis), and selecting other mandatory attributes and/or adders and penalties that may be appropriate for screening and ranking proposals for cost-effectiveness.

4.3 Key Resources

BC Hydro's 2006 IEP analysis and the resulting LTAP was designed to fill the forecast "gap" between the expected demand for electricity and the existing and committed supply of resources that BC Hydro has available to it. Given the 2002 Energy Plan, BC Hydro identified four general categories of sources that it can rely upon to fill the supply gap:

- DSM measures including energy efficiency, conservation and LD;
- Resource Smart projects at Heritage Resource sites;
- acquisitions from the private sector in BC (IPPs and other third party suppliers), including a voluntary acquisition target for BC Clean Electricity resources; and
- imports.

BC Hydro suggested the first three may be considered long-term sources. These were described as the big “buckets” in the proceeding (T7:703-04). BC Hydro testified these three buckets are grounded in the 2002 Energy Plan and were an integral part of the First Nations and stakeholder consultation processes (T8:1044-45). BC Hydro expects that there will be a need to acquire resources from each of the three “buckets” to be able to fill the load/resource gap. The fourth category or bucket can be either a firm source, a default supply of last resort in any event where there is or becomes a residual gap, or a source or sink of electricity that can be used to operate the system more efficiently and to maximize trade benefits.

According to BC Hydro, the 2006 IEP/LTAP process was designed to start with the portfolio analysis, from that analysis to identify the three big buckets, and from there create a plan for the acquisition processes involved to acquire resources from each of the buckets (BC Hydro Argument, p. 68). By designing the process in this way, BC Hydro submits “the portfolio analysis could meet BC Hydro planning objectives, comply with the BCUC *Resource Planning Guidelines*, and work within the framework set by the 2002 Energy Plan” (BC Hydro Argument, p. 68).

(a) DSM Bucket

BC Hydro states DSM is a cornerstone bucket in its 2006 IEP. BC Hydro submits that DSM, as identified by EE 3, EE4 and EE5, is one of the lowest cost resources in the 2005 ROR when measured in $/MW.h, with EE 3 and EE4 being the two lowest costs of the generic options. BC Hydro proposes to fill about a third of the load/resource gap with DSM sources. BC Hydro submits this amount is both achievable and is cost-effective. BC Hydro proposes to complete the Definition phase work and file an Implementation plan, which will confirm the achievability and cost-effectiveness of this resource. BC Hydro submits DSM is consistent with the 2002 Energy Plan and recent statements by the Minister of Energy, Mines and Petroleum Resources.

(b) Resource Smart Bucket

According to BC Hydro, the Resource Smart bucket is relatively limited in scope as it refers to projects at BC Hydro's Heritage sites. With the exception of the capacity projects at Mica and Revelstoke, the amount of capacity or energy available from most projects is much less significant than either DSM activities or acquisitions from IPPs in the overall 2006 IEP/LTAP context.

CPC notes that in its evidence (T15:2286a (amended)) and its Argument (BC Hydro Argument, pp. 100-101), BC Hydro has acknowledged that the Waneta Expansion Project, which is the responsibility of CPC and the Columbia Basin Trust (collectively, "CPC/CBT"), has attributes similar to Resource Smart projects, namely upgrades at existing facilities that tend to be cost-effective and do not have additional adverse environmental impacts. CPC notes that "[w]hen asked to identify non-BC Hydro projects with Resource Smart attributes, Panel 5 witnesses identified only three: CPC/CBT's Waneta Expansion Project, CPC/CBT's Brilliant Expansion Project and a potential expansion at an 'existing waste IPP project in Vancouver'" (CPC Argument, p. 3). CPC argues:

> "The same attributes that justify the priority development of BC Hydro's own cost-effective Resource Smart projects equally justify the priority development of cost-effective non-BC Hydro Resource Smart-like projects. Every effort, including alternative acquisition processes as required, should be made to facilitate their optimal and timely development" (CPC Argument, p. 4).

BCOAPO strongly supports Revelstoke Unit 5, and submit that BC Hydro should further investigate Revelstoke Unit 6 and Mica Unit 5.

The JIESC considers BC Hydro's Resource Smart projects low price capacity additions (JIESC Argument, p. 16).

CEC supports BC Hydro's Resource Smart projects and encourages BC Hydro to file as soon as possible for a CPCN for Revelstoke Unit 5 and to proceed with a full evaluation of the other projects at Revelstoke and Mica (CEC Argument, p. 55).

(c) IPP Bucket

Acquisitions from other persons through competitive processes form a major portion of BC Hydro's future plans. Outside of Resource Smart projects, BC Hydro's options to construct new resources are very limited since the 2002 Energy Plan. Alternative new supply must come from the IPP community and third party suppliers.

BC Hydro submits that no evidence was filed during the evidentiary phase of the 2006 IEP/LTAP proceeding, nor questions raised challenging the appropriateness of pursuing resources from each of the three key resource buckets.

CPC understands that BC Hydro's phrase "third party suppliers" includes CPC/CBT power project companies. However, CPC argues the Waneta Expansion Project shares most attributes of both the Resource Smart and the IPP buckets. As a result, "CPC encourages BC Hydro to develop the structure, terms and conditions of the 2007 Call or alternative acquisition processes in a manner that appropriately accommodates and values the unique attributes and benefits of Resource Smart-like non-BC Hydro supply options" (CPC Argument, p. 4).

BC Hydro proposes to update its resource options with the following (BC Hydro Reply, pp. 21-22):

- the current status of the availability of cost-effective DSM to meet new Provincial Government targets;
- the current status of carbon sequestration technology development to gauge the likelihood of coal-fired generation development and the associated costs;
- the impact of the 100 percent GHG offset and 90 percent clean, renewable Throne Speech pronouncements on the operating costs and availability of natural gas-fired generation projects, including Burrard's operating costs;

- the impact and cost of wind integration;
- an assessment of the energy and capacity potential for biomass energy from woodwaste and beetle-killed lumber;
- the volumes of firm energy and dependable capacity contributed by clean, intermittent resources on a portfolio basis; and
- large energy supply sources, including Site C, in addition to clean, renewable resource potential.

Commission Determination

The Commission Panel finds the concept of "resource buckets" a useful tool for organizing resources into broad categories for the purposes of creating and communicating alternative resource portfolios. However, there are some key resources that do not appear to be reflected in BC Hydro's "buckets" as defined above, including Burrard repowering (which may be considered a Resource Smart project, although it is not explicitly characterized as such), Site C and the CE, although Site C and Burrard are considered in the trade-off analysis.

The Commission Panel agrees that, in light of the statements within the Throne Speech regarding self-sufficiency, imports may indeed be considered a short-term resource. However, a more explicit definition of self-sufficiency will be required to confirm this assumption. For example, it is not at all clear yet whether relying on CE to provide incremental capacity or reserves would be inconsistent with a policy of self-sufficiency. The Commission Panel notes that any incremental reliance on CE (over and above the 400 MW used for reserves) would require further examination of transmission availability (and any costs associated with increasing availability).

With respect to CPC's concerns about whether its projects should be considered Resource Smart or IPP projects, the Commission Panel finds little value in making any determination on this issue. There are likely other IPP projects that may be incremental additions to existing IPP facilities and CPC provides no specific suggestions regarding how the existing or alternative acquisition processes should be structured to facilitate the optimal and timely development of what it has characterized as non-BC Hydro resource smart projects. The Commission Panel considers the Resource Smart bucket as merely encompassing projects that may be developed by BC Hydro, which would have some advantage in terms of financing costs.

4.4 Trade-off Analysis

The trade-off analysis is summarized in Section 7 of the IEP (Exhibit B-1A). The trade-off analysis compared the performance of different portfolios of supply-side and demand-side resources to meet customers' electricity needs across various evaluation attributes and under different scenarios for key uncertainties such as future market gas and electricity prices and GHG costs (Exhibit B-1A, Sections 7.2.1 through 7.2.5). The trade-off analysis also considered the transmission implications of different resource portfolios (Exhibit B-1A, Section 7.2.6). The analysis was structured to test varying types of resources and combinations of resources, as opposed to different resource developers (e.g., BC Hydro vs. the IPPs). BC Hydro used a range of discount rates in the analysis to reflect a reasonable range of costs under alternative ownership scenarios for each resource (BC Hydro Argument, p. 70).

BC Hydro identified five key questions/concepts to explore in the trade-off analysis: (1) Resource Mix; (2) DSM; (3) Site C; (4) Burrard; and (5) Security of Supply. A total of 17 portfolios were assembled and tested against a list of uncertainties and sensitivities (Exhibit B-1A, Section 7.2). The table below summarizes the performance of all 17 portfolios against BC Hydro's 14 evaluation attributes.

Summary of BC Hydro Portfolio Analysis

Table 6-4 Attribute Results Summary

ATTRIBUTE RESULTS SUMMARY IN YEAR 2025 – ALL PORTFOLIOS

ATTRIBUTE	UNITS	PORTFOLIO																
		Coal	Low Air Impact	Low Air Impacts without Energy Efficiency 3.4 or 5	Low Land Impact	Diverse Technology	100% Green	"Low Cost" (mid-GHG)	"Low Cost" without Site C (mid-GHG)	"Low Cost" without PS3, PS4 & PS5	"Low Cost" ($10/6 GHG)	Maintain BGS	"Low Cost" (3000 GWh Imports)	Maintain BGS for Capacity	Repower BGS	"Low Cost" (up to 6000 GWh Imports)	Security of Supply with Insurance	Security of Supply
Financial																		
PV (mid-GHG, 6%, EIA100)	$m	$4,902	$4,330	$5,207	$4,408	$4,635	$4,549	$4,339	$4,540	$5,039	$4,667	$4,261	$4,271	$4,344	$4,267	$4,178	$4,824	$4,458
Rate Impact (in 2025 over 2005)	%	17.1%	6.6%	17.9%	13.0%	12.6%	11.0%	7.0%	11.2%	15.2%	12.1%	7.1%	6.2%	8.6%	5.3%	6.4%	7.4%	5.9%
Regional Equity																		
Overall Regional Equity	%	37.2%	42.7	48.8%	52.9%	48.5%	46.7%	43.9%	43.9%	41.8%	39.8%	46.1%	44.7%	43.9%	47.1%	43.9%	41.0%	43.8%
Technical Diversity																		
# of Resource Types	#	4	5	5	4	7	5	6	5	6	6	5	5	5	5	6	6	6
Green Energy Resource Mix																		
% of Total New Energy	%	13.1%	71.0%	79.9%	30.1%	32.3%	96.6%	50.1%	50.1%	34.1%	24.5%	52.4%	50.1%	50.1%	20.0%	50.1%	77.1%	70.9%
BC Clean Electricity Resource Mix																		
% of Total New Energy	%	15.6%	100.0%	100.0%	40.7%	50.9%	100.0%	78.9%	53.2%	53.8%	49.7%	100.0%	79.1%	78.0%	48.8%	78.9%	100.0%	100.0%
Ownership																		
% Public	%	2.0%	19.7%	20.1%	1.8%	2.1%	2.3%	19.6%	2.1%	19.7%	19.6%	26.8%	33.9%	18.9%	54.4%	19.6%	2.0%	19.8%
% Private	%	98.0%	80.3%	79.9%	98.2%	97.9%	97.7%	80.4%	97.9%	80.3%	80.4%	73.2%	66.1%	81.1%	45.6%	80.4%	98.0%	80.2%
Impacted Land Area																		
Total Land Area	ha	6,020	9,359	11,042	1,215	2,808	3,649	8,822	2,715	10,112	11,266	8,387	8,950	9,836	8,054	8,822	9,620	9,199
Impacted Aquatic Area																		
Total Aquatic Area	ha	57	4,242	4,365	169	98	323	4,167	194	4,180	4,092	4,069	4,169	4,178	4,018	4,167	4,295	4,240
GHGs (cumulative)																		
BC Total Emissions	1000 tonnes	118,718	12,906	13,020	36,514	60,542	12,914	16,714	27,293	34,204	83,954	19,778	12,935	16,881	40,426	13,926	11,167	11,340
Baseline Emissions	1000 tonnes	52,023	11,735	11,809	32,609	37,253	11,743	15,131	24,732	30,940	38,984	15,694	11,763	15,280	37,410	12,637	10,610	10,749
Over Limit Emissions	1000 tonnes	66,695	1,171	1,210	3,904	23,289	1,171	1,583	2,561	3,263	44,971	4,085	1,172	1,601	3,016	1,289	558	591
Employment																		
Temporary	FTEs	1,474	2,544	1,095	2,068	2,205	2,400	2,424	2,112	900	1,792	2,271	2,425	2,391	2,232	2,424	2,718	2,655
Full-Time	FTEs	443	281	410	499	444	430	265	290	365	368	160	215	264	209	265	455	384
Local Air Emissions (cumulative)																		
NOx	tonnes	81,705	87	89	381	27,861	3,499	134	264	349	54,860	206	87	136	419	99	5,915	1,065
SOx	tonnes	18,634	1,309	1,325	5,393	16,897	14,642	1,853	3,363	4,350	12,941	2,259	1,312	1,877	5,243	1,454	21,418	5,866
CO	tonnes	11,222	88	93	3,986	16,243	24,384	740	2,549	3,719	7,561	382	88	768	4,933	260	39,072	8,060
VOC	tonnes	1,252	5	16	634	780	1,375	123	425	620	845	64	15	128	822	43	3,539	4
PM 10	tonnes	1,855	0	0	13	5,658	10,188	0	0	0	1,245	0	0	0	0	0	14,431	4,019
PM 2.5	tonnes	500	500	501	2,406	1,517	501	826	1,732	2,316	501	567	501	841	2,937	588	480	485
Hg	tonnes	359	0	0	0	116	0	0	0	0	241	0	0	0	0	0	0	0

Notes:

1. Technical Diversity excludes Demand Site Management, Imports, Other and Transmission.
2. Employment units of FTEs equals full time equivalent jobs. One FTE for Temporary Employment is based on 20 years of temporary work such as construction.

Source: Table 6-4, p. 6-19, BC Hydro 2006 Integrated Electricity Plan

In Argument, BC Hydro notes that the "…trade-off analysis is not intended to reinstitute centralized planning and decision-making… [but]… to provide the contextual framework of what the result would be if certain portfolios were actually to be acquired" (BC Hydro Argument, pp. 70-71). Ultimately, BC Hydro notes, the actual resource acquisitions will be through competitive calls and other means that demonstrate cost-effectiveness. The trade-off analysis formed the basis for a large part of the First Nations and stakeholder input.

Each of the questions explored by BC Hydro is discussed below, together with comments from Intervenors.

4.4.1 Resource Mix

Using input from regional stakeholders, PIEPC members and First Nations, BC Hydro designed seven portfolios to test what mix and volumes of resources BC Hydro should acquire and how these resources should be acquired. The portfolios were designed to test questions such as:

- 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 percent 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?

(Exhibit B-1A, Section 7.2.1)

The seven resource mix portfolios were designed around the following themes:

- "Low Cost" (based on mid-GHG cost assumptions);
- "Low Cost" (based on GHG cost assumptions of $10/tonne);

- Low Air Impact;
- Low Land Impact;
- Diverse Technology;
- Coal; and
- 100 % Green.

Details of the specific Resource Mix portfolios are found in Table 7-1 of Exhibit B-1A.

According to BC Hydro, a key finding of the Resource Mix analysis was that there are a wide range of resources that can provide a low cost mix and meet the 50 percent BC Clean Electricity target. BC Hydro notes that all of the Resource Mix portfolios also show that at least 900 MW of new capacity resources are required in addition to the assumed capacity that comes with the energy resources in the various portfolios (BC Hydro Argument, p. 71). The analysis also showed that while there appears to be an adequate volume of Green Energy or BC Clean Electricity to meet customers' needs, this portfolio is higher cost than the "Low Cost" (mid-GHG) portfolio. The "Low Cost" (mid-GHG) and Low Air Impact portfolios are both low cost and low risk. GHG offset liabilities and gas and electricity market prices could have significant impacts on costs (Exhibit B-1A, Section 7.2.1.6).

4.4.2 DSM

DSM resources were prominent in most of the portfolios analyzed by BC Hydro. However, five portfolios were developed specifically to test the cost-effectiveness of DSM programs under various scenarios (Exhibit B-1A, Section 7.2.2.1). BC Hydro's current DSM program includes EE2 and LD2. Based on the 2002 CPR, BC Hydro identified three additional DSM programs:

- EE3 – approximate energy savings of 2,600 GW.h/yr by F2018;
- EE4 – approximate energy savings of 2,500 GW.h/yr by F2024;

- EE5 – approximate energy savings of 2,200 GW.h/yr by F2024.

During the hearing, BC Hydro testified that DSM was one of the most cost-effective of the resources considered and was not any more reliant on planners' judgment than any of the other supply resources (T9:1272-73). EE3, EE4 and EE5 were considered among the lowest cost resources in the IEP based on unit energy cost and measured in levelized $/MW.h (Exhibit B-1A, Table 5-1).

The JIESC supports continuation of BC Hydro's current DSM programs but does not agree with a defined volume of energy to be acquired from DSM. Rather, the JIESC submits that programs should be chosen based on the comparison of their cost-effectiveness to available alternatives (JIESC Argument, p. 14).

Terasen submits that the evidence in these proceedings and the content of the Throne Speech support inclusion of EE3, EE4 and EE5 in BC Hydro's LTAP.

BCOAPO supports the development of all DSM resources that are cost-effective, as determines using the Utility, All Ratepayer and Non-Participant Tests (BCOAPO Argument, para. 78-79). However, BCOAPO argues the outstanding and single most important issue in determining the cost-effectiveness of DSM is determining the appropriate avoided cost measure for DSM (BCOAPO Argument, para. 81).

4.4.3 Site C

BC Hydro notes that the Provincial Government must ultimately decide whether or not Site C should be pursued. However, the 2006 IEP contains four portfolios that compare Site C with other potential supply alternatives to assist the Provincial Government with its decision. BC Hydro submits that based on a range of initial estimates of the capital costs of the Site C project, the analysis suggests that Site C is within the range of costs of other resource options (BC Hydro Argument, p. 72).

The JIESC considers Site C "…as a potentially very attractive and important resource for British Columbia, providing much needed additional capacity and energy through the efficient use of the existing vast storage capabilities on the Peace River" (JIESC Argument, p. 14). The JIESC argues there are no other projects that can provide as much reliable energy with so little additional impact on the environment at such a favourable cost, even with substantial increases in unit costs. The JIESC suggest this option needs to be revisited given the Throne Speech, which has changed the other options open to BC Hydro. The JIESC also argues Site C should not only be considered a resource, but also a benchmark for testing the cost-effectiveness of alternate IPP, DSM, and Resource Smart options (JIESC Argument, p. 14).

CEC notes that BC Hydro is spending significant sums of money on the Site C project at the request the Provincial Government, which will make the final decisions on whether or not to pursue the project (CEC Argument, p. 48). Even with substantial allowances for increased costs, CEC submits the power from Site C would still be relatively inexpensive. CEC submits there is little doubt that the Site C project is a strategic choice for the province (CEC Argument, p. 49).

SCCBC submits: "The fact that the Government has chosen not to announce any intention even to consider moving to Stage 2 on Site C establishes that, at least for the time being, Site C is not a viable resource option. SCCBC, *et al* respectfully submit that Site C should be taken out of BC Hydro's 2010 IEP resource portfolios unless or until the government indicates otherwise" (SCCBC Argument, p. 21).

BC Hydro rejects SCCBC's assertion that the fact that the Throne Speech does not mention Site C by name means that Site C is "not a viable resource option" and sees no need for the Commission to act on SCCBC's request that BC Hydro take Site C out of the 2010 IEP resource portfolios (BC Hydro Reply, p. 22). In a follow-up letter dated March 12th in response to Commission's March 8, 2007 letter inviting further comments on matters raised by BC Hydro in its Reply in relation to the Throne Speech, SCCBC withdrew its comments regarding Site C (Exhibit C25-25, p. 2).

4.4.4 Burrard

A key question for BC Hydro in the 2006 IEP portfolio analysis was whether to maintain, replace, or repower Burrard. Burrard is the only gas-fired facility BC Hydro could develop under current government policy (T9:1103-05). BC Hydro developed seven portfolios to explore alternatives for Burrard, looking at both capacity and energy impacts on the system (Exhibit B-1A, Section 7.2.4). BC Hydro submits that the Burrard portfolio analysis demonstrated that there is an opportunity to replace Burrard's energy capability due to the high operating costs of running Burrard. At the same time, BC Hydro notes that the "Maintain Burrard" portfolio showed significant amounts of plant use (expected annual GW.h of generation) even in relatively average water conditions, particularly in the latter 10 years of the IEP analysis period. However, BC Hydro argues "[s]uch forecast levels of generation at Burrard are significantly above what is currently planned or budgeted. It is also higher than local stakeholders may be prepared to tolerate" (BC Hydro Argument, p. 73).

The Maintain Burrard and Repower Burrard portfolios had among the lowest cost of all portfolios, although the Repower Burrard portfolio also showed the greatest sensitivity to high gas prices (Exhibit B-1A, Figure 7-9). BC Hydro observes that no Intervenor raised the issue of Burrard repowering through information requests or during cross-examination of BC Hydro's witness panels (BC Hydro Argument, p.107). However, the issue of Burrard repowering was raised by the Commission Panel during the hearing. Specifically, the Commission Panel raised questions regarding the relationship of Burrard repowering to the 2007 and 2009 Calls, and whether Burrard repowering would be a useful benchmark for use in the 2007 Call (T10:1356-57). BC Hydro indicated the call will not be set up with a reference price based on Burrard repowering as that would by unfair to bidders that may put in considerable time and money into preparing their bids (T10:1360). BC Hydro noted:

> "…we don't know the certainty of the costs of repowering Burrard, so that's an unknown today. We don't know how we would go about re-powering Burrard. Would we build that project ourselves? Would we run a competitive call, and have a private-sector proponent do that? I don't know. We've not answered any of those questions from a policy perspective at B.C. Hydro, so I don't know the answer to those. So there's lots of uncertainty as to where you'd end up on a unit energy cost on

> Burrard. So I think it would be difficult to factor that in without taking into account all of the assumptions that went into that, and knowing that that is a range that potentially can move" (T10:1376-77).

However, BC Hydro also acknowledged that Burrard repowering remains a viable option in the long-run:

> "I think that -- I think we believe that we still have the option to develop the repowering of Burrard, and if the conditions were to change in the next couple of years or in the next timeframe, there's quite a time between now and 2014 that we could bring that option forward. So I don't think I could say definitely that we know that you would never attempt to develop Burrard -- to develop a re-powering of Burrard" (T10:1355)

BC Hydro committed to study the costs of Burrard repowering as part of the 2007 Call Definition phase work subject to any changes in Provincial Government policy (Exhibit B-17-3, BCUC 4.451.4).

During the proceeding the important role played by a gas-fired facility was explored (and, as noted above, Burrard is the only natural gas-fired facility BC Hydro could develop under current government policy). BC Hydro's generation operations witness testified that it was necessary, once the planning people had met their requirements, for the operating people to go to the layer underneath and see how the shaping of the planned resources "compliments the loads that we have….[a]nd my concern on the operational basis is that the final portfolio may satisfy the planning criteria, but we have to make very sure it also satisfies the layer under, otherwise we will find ourselves still mismatched during different periods of the year" (T15:2257). "If all I get is run of river hydro that's going to be producing during freshet, I'm in trouble … And so, I know if ...I had a gas facility… that was reliable for the longer term…near the load and had the pipe to go with it …firm pipe… and I knew I can get the gas there and it was dispatchable, then yes it would give me a huge amount of flexibility" (T15:2258).

BCOAPO suggests that "Burrard is ideally located in the sense that it is close to load and the necessary pipeline and transmission facilities. In this hearing there has been a considerable body of evidence put forward, based on high-level budget estimates, to indicate that Burrard may be a cost-effective plant" (BCOAPO Argument, para. 105). BCOAPO suggests the fate of Burrard may ultimately hinge on the meaning of the ambiguous concept "net zero greenhouse gas emissions by 2016" in the Throne Speech (BCOAPO Argument, para. 102). In any event, BCOAPO recognizes that Burrard repowering would face many challenges. BCOAPO notes that BC Hydro's preferred approach to end Burrard's availability for planning purposes in 2014, and replace Burrard's energy and capacity capability with IPP purchases coming out of the 2009 Call may be premature unless IPP developers can improve their ability to bring projects on time and to deliver firm capacity. BCOAPO suggests this is "one of the issues which call for leaving options open until future developments, including the elaboration of federal and provincial policy, are apparent" (BCOAPO Argument, para. 108).

CEC submits BC Hydro must plan at some time to cease relying on Burrard. CEC further submits that Burrard can and should have a back-up insurance role after 2014 and as a contingency option may be quite useful for a time. The questions of replacement, continued maintenance, or repowering of Burrard are major strategic provincial related decisions and CEC understands that BC Hydro is appropriately working with the Province to determine if, where, when and how these questions should be considered (CEC Argument, p. 50).

The JIESC considers the existing Burrard plant a valuable source of capacity at this time, and potentially energy. Furthermore, "JIESC strongly supports the plans of BC Hydro to maintain Burrard in an operational state for as long as it is cost-effective to do so, and to maintain the potential for repowering Burrard for now, but not to take further action on repowering Burrard at this time" (JIESC Argument, p. 15). The JIESC also agrees with BC Hydro that "while there needs to be a retirement date for Burrard for planning purposes, that date should not be taken as the date that Burrard will in fact be retired" (JIESC Argument, p. 15). The JIESC also opposes the "parallel path" suggestions for seeking approval of Burrard and ILM raised by the Chair at T20:3050. The JIESC submits that Burrard repowering appear to contravene the requirement for 90 percent Clean

Energy sources in the Throne Speech and the JIESC also considers Burrard repowering “too big to be practical” (JIESC Argument, p. 15). The JIESC also suggests that “expenditures for the purpose of attempting to obtain environmental permits for Burrard at this time would be high and could unnecessarily and inappropriately complicate the permitting of ILM as it could give parties opposed to ILM a false sense that there was a realistic possibility of an alternative” (JIESC Argument, p. 16). The JIESC does not appear to preclude eventual repowering but suggests it is not the next economic alternative compared and supports instead proceeding with ILM and capacity additions at Revelstoke and Mica and additional IPP development.

IPPBC agrees with BC Hydro’s assessment that the current Burrard plant “should be viewed as a capacity resource and that it is masking energy market purchases” and argues new domestic sources of energy must be brought on line to reduce the risk associated with these market purchases (IPPBC Argument, p. 17). IPPBC also does not consider Burrard repowering a viable option in the foreseeable future (IPPBC Argument, p. 20).

Mr. Campbell, a director of the IPPBC and a project developer, testified as to the perception of gas fired generation in Ontario saying that in Ontario natural gas played two roles - to displace the coal fleet and as a “medium use back up to renewables….50,60 percent of the time when renewables aren’t on line, they act as back-stopping for that, and certainly its very positively viewed….the coupling of renewables with gas fired generation gives you a total energy solution.[It] makes sure the lights stay on….the environmental lobby in Ontario is 100 percent behind the change” (T23:3648).

Mr. Campbell also cites Sithe and Portlands as two large combined cycle gas fired generating projects, which have been permitted in Ontario (T23:3739-40).

SCCBC supports BC Hydro’s decision to discontinue reliance, for planning purposes only, on Burrard at the end of F2014 and supports BC Hydro’s conclusion that the concept of repowering the Burrard is not realistic from a development risk perspective (SCCBC Argument, p. 21).

BC Hydro "acknowledges that any future plans for Burrard will require careful consideration in light of the proposed net-zero GHG offset and the 90 percent clean, renewable pronouncements set out in the Throne Speech" and notes that "[t]he proposed GHG targets are likely to add to the cost of operating Burrard as currently configured, and also add to the cost of any repowering of Burrard" (BC Hydro Reply, p. 16). BC Hydro further submits that "in light of the overwhelming, uncontradicted evidence as to the many reasons why BC Hydro is not proceeding with Burrard repowering at this time, and in light of evolving Provincial Government policy, the BCUC should refrain from directing BC Hydro to further investigate the repowering of Burrard" (BC Hydro Reply, p. 27).

4.4.5 Security of Supply

BC Hydro considers security of supply fundamental. BC Hydro developed seven portfolios to test whether it should continue to use the wholesale spot market as a component of its supply portfolio. BC Hydro conducted additional analysis of the Security of Supply portfolios to present the impacts of potential increases in capital costs of resources as compared to the 2005 ROR. BC Hydro argues that the security of supply analysis supports moving in a direction that reduces reliance on wholesale spot markets in average to dry hydro conditions. This will result in increased surpluses in above normal water years. BC Hydro indicates that security of supply enjoyed broad support from stakeholder participants. Specifically, BC Hydro notes that PIEPC members achieved consensus on security of supply as a desirable position, and generally opposed relaxing security of supply to allow BC Hydro to rely on the spot market for energy (BC Hydro Argument, p. 74).

During the proceeding, BC Hydro introduced the concept of self-sufficiency and sometimes confused it with security of supply but, when questioned, agreed that supply security was distinct from and more important than self-sufficiency:

> "THE CHAIRPERSON: So from your perspective, did you say that having enough is a more important objective than self-sufficiency?

MR. ELTON: A: For B.C. Hydro and its customers, I believe yes" (T8:902).

The Throne Speech indicated that the new energy plan will require British Columbia to be electricity self-sufficient by 2016.

BCOAPO argues that "[p]olicies that have been adopted by the provincial government but not given statutory significance through Directions to the Commission have no binding authority, but may inform the Commission's determinations" (BCOAPO Argument, para. 22). BCOAPO also argues that policies that "have not been substantially defined or formulated should have no bearing on the exercise of the Commission's powers" (BCOAPO Argument, para. 24). BCOAPO submits that the Provincial Government has not yet provided explicit definition or direction regarding self-sufficiency. As a result, BCOAPO submits "[I]f there is an available choice between committing to a higher-cost domestic resource, and a reliable and lower-cost external one… BC Hydro should be required to prefer the latter" (BCOAPO Argument, para. 28). BCOAPO also suggests that any version of such a policy would violate the spirit of the recent trade accord with Alberta (BCOAPO Argument, para. 33) and may eventually be overtaken by regional, continental and global considerations related to climate change (BCOAPO Argument, para. 29).

The JIESC submits that "…security of supply is vital and accepts that, at this time, it is essential to move in the direction of obtaining additional fixed price long-term firm resources" (JIESC Argument, p. 7). The JIESC submits that while movement towards self-sufficiency is good, "…in the longer term, the goal of self sufficiency needs to be better understood… and how it should be distinguished from 'security of supply'" (JIESC Argument, p. 8). However, the JIESC submits that given BC Hydro's current energy and capacity shortfall, acquiring new resources is a common priority of all stakeholders and the long-term meaning of self-sufficiency or security of supply does not need to be defined today.

Terasen supports BC Hydro's intention to reduce exposure to short term market commodity risk but suggests the risk is better represented by the 12 percent market exposure under average water conditions than the 18 percent under critical water conditions (Terasen Argument, para. 14-15).

Terasen also submits that the results of the F2006 Call indicate that the marginal cost of new electric generation is rising at a higher pace than originally anticipated by BC Hydro and this consideration should be carried into other BC Hydro cost and rate related submissions, including BC Hydro's Rate Design Application (Terasen Argument, para. 26).

IPPBC agrees with BC Hydro's assessment that it is too reliant on the spot market and should move towards more energy security, which IPPBC also considers consistent with the Province's goal for electricity self-sufficiency (IPPBC Argument, p. 18). IPPBC also agrees with BC Hydro's desire to gain the security and price stability of long-term electricity contracts. IPPBC suggests that while "short term market purchases may appear attractive at first glance… [they] leave the ratepayers exposed to the type of price volatility that occurred in F2001 and F2002" (IPPBC Argument, p. 15).

BC Hydro submits that the Commission cannot ignore the Province's commitment to self-sufficiency and suggests the Throne Speech is black and white with respect to this commitment. BC Hydro also agrees with the JIESC's proposal to examine the impacts of self-sufficiency in the next LTAP (BC Hydro Reply, pp. 48-49). With respect to Terasen's argument concerning the magnitude of BC Hydro's exposure, BC Hydro notes that for reliability planning purposes it plans its system on the basis of critical water.

4.4.6 Transmission Implications

The transmission implications of the portfolios were identified by BCTC and presented in Appendix H of the Application. Of the nine significant transmission system reinforcements that were identified, the key requirement is the ILM transfer capacity upgrade (Exhibit B-1A, p. 7-49). A table was provided that showed for each portfolio which of the nine identified transmission system reinforcements was required, and the associated in-service dates. The timing of the elimination of Burrard for planning purposes was also shown for each applicable portfolio as April 2014, presumably to show the effect on transmission reinforcement timing (Exhibit B-1C, Appendix H, Table H-1).

BC Hydro proposed that either by necessity or by the benefits associated with risk mitigation, the ILM project should be implemented at its earliest in-service date. BC Hydro stated that the "Low Land Impacts" portfolio was the only portfolio in which the ILM project is not required, and only because the portfolio was specifically designed to test the sensitivity of not building new transmission lines. For all other portfolios, the ILM project is required between October 2013 and October 2020.

The "Low Land Impacts" portfolio requires four of the nine identified transmission system reinforcements and shares the fewest number of transmission system reinforcements with one other portfolio, that being the "Maintain Burrard For Capacity" portfolio. The "Maintain Burrard for Capacity" portfolio demonstrates the importance of a capacity resource located at the load centre for deferring the need for investment in the transmission system. However, BC Hydro notes that Burrard is not currently nominated as an RMR resource (Exhibit B-1A, pp. 7-49 to 7-50).

The planning assumptions used in BCTC's analysis for the 2006 IEP/LTAP were described in Appendix H of the Application. BCTC assumed that the ILM reinforcement would be implemented as the 500 kV circuit between the Nicola and Meridian substations, at an earliest in-service date of October 1, 2013, and that October 31, 2008 was the earliest in-service date for the new 230 kV circuit from the Lower Mainland to Vancouver Island. BCTC also included BC Hydro's firm export obligations and the power transfer obligations of BCTC's other customers when assessing the bulk transmission system capabilities. For those portfolios where CE is scheduled as a resource, 11/14ths of the resource was designated as an import flow on the U.S. to Lower Mainland transmission intertie, and 3/14ths as an import flow on the U.S. to Nelway transmission intertie in the South Interior (Exhibit B-1C, Appendix H, pp. 3-4).

However, in a joint letter to the Commission, BC Hydro and BCTC described some of the underlying planning assumptions that were used in determining the transmission implications for the IEP analysis and in the preliminary evaluation process for the LTAP and CRPs, and how these assumptions may change when applied to BC Hydro's NITS application (Exhibit B-102). The key planning assumptions that may change when applied to the NITS application fall into three broad categories, these being coastal generation, interior Heritage resource dispatch, and the treatment of intermittent resources.

The issue with coastal generation, including Burrard and the proposed facilities from the F2006 Call, is the amount of generation that was identified for regional reserve requirements and RMR considerations. With respect to regional reserves, the IEP portfolios reduced the amount of dependable capacity available for RMR whereas the amended LTAP and NITS application review considers the total aggregate coastal generation is available as RMR, with no reduction for reserves. Furthermore, the IEP portfolios assumed 39 MW of incremental coastal generation from the F2006 Call, as compared to 160 MW for the amended LTAP and NITS application review. For the purposes of the IEP portfolios and the NITS application, Burrard is only used until the ILM project is implemented, but the amended LTAP utilizes full Burrard capacity in order to defer the need for the ILM project.

The issue with interior resource dispatch is the use of dependable generating capacity (“DGC”) for the IEP portfolio analysis and LTAP and CRP evaluation, and the use of maximum continuous rating (“MCR”) for BC Hydro’s NITS application. The MCR of the interior Heritage hydroelectric facilities is approximately 390 MW greater than the DGC. BC Hydro stated that the transmission system has historically been planned on the basis of MCR, and the next NITS application will be made on that basis.

A similar issue was also applicable to the treatment of intermittent resources, in which the ELCC was used for the IEP portfolio analysis and LTAP and CRP evaluation, while MCR and DGC would be used in BC Hydro’s NITS application for the purposes of identifying the need for new transmission or deferring the need for new transmission, respectively.

Commission Determination

The Commission's Guidelines state: "For each of the gross demand forecasts, the set of alternative resource portfolios that match the forecast are assessed against the objectives. Analysis of the tradeoffs between portfolios and how they perform under uncertainty will facilitate determining which portfolio performs best relative to the stated objectives. This process will lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts."

The Commission Panel notes that BC Hydro's trade-off analysis is generally consistent with the methodology suggested in the Commission's Guidelines and, although BC Hydro did not select a preferred portfolio, the Commission Panel accepts BC Hydro's general approach to the trade-off analysis. However, the Commission Panel does not see clearly articulated linkages between BC Hydro's trade-off analysis and its LTAP. The Commission Panel expects BC Hydro to establish a clear link between the results of its trade-off analysis and the proposed action plan in its next LTAP.

The Commission Panel also notes that a key option was not explicitly considered in the portfolio analysis, namely increased reliance on the CE as a source of capacity for the Lower Mainland, not merely for contingency planning purposes. The Commission Panel expects BC Hydro to provide more explicit analysis of this option in its next IEP. This portfolio, of course, will require additional analysis of transmission availability and consideration of any interactions with BC Hydro's continued reliance on 400 MW of reserve sharing with neighbouring jurisdictions.

The Commission Panel considers BC Hydro's analysis of security of supply inadequate, in that much of BC Hydro's analysis and argument seemed to revolve around unarticulated notions of self-sufficiency. BC Hydro could have facilitated a more constructive discussion of this issue by making clearer distinctions among market exposure (price certainty), physical supply security and self-sufficiency. BC Hydro acknowledged that supply security is a distinct, and more important, concept. The Commission Panel expects BC Hydro to continue to make security of supply an objective regardless of any self-sufficiency requirements.

The Commission Panel notes that reduced market price exposure is not synonymous with increased physical supply security or with self-sufficiency, particularly since domestic supplies may be acquired at market-based prices. The Commission Panel provides comments on BC Hydro's analysis of and approach to its market exposure in Section 5 of this Decision.

The Commission Panel agrees with BCOAPO that the Provincial Government's pronouncements regarding self-sufficiency prior to and within the Throne Speech still lack any clear definition or legal support. However, BC Hydro could have helped clarify the possible impacts of such a policy by providing some alternate definitions for self-sufficiency. For example, what are the impacts if self-sufficiency were measured under average or critical water conditions, if self-sufficiency targets were applied to energy and/or capacity, if the policy precluded net imports under any conditions such as when imports are cheaper than dispatchable (but physically available) domestic resources, or if reliance on a resource such as the CE were inconsistent with such a policy.

The Commission Panel notes that given BC Hydro's existing reliability planning criteria, which require the company to acquire sufficient firm resources to meet demand under critical water conditions, the main impacts of a self-sufficiency policy could be to alter the ability of BC Hydro to rely on firm imports (if firm transmission capacity is available) and market purchases as part of its 2,500 GW.h/yr non-firm / market allowance. As noted below, at this time the Commission Panel considers the issue of continued reliance on Burrard an economic one and not a self-sufficiency issue. These concerns notwithstanding, the Commission Panel finds that the government's self-sufficiency pronouncements do not impact on the immediate decisions before the Commission in this proceeding. The Commission Panel expects a more coherent and compelling analysis of these issues, taking into account legally supported government policy, as part of BC Hydro's next IEP/LTAP applications.

Given the role of the Provincial Government in approving the development of Site C, concerns expressed by CEC regarding expenditures on Site C and their deferral account treatment are best addressed in BC Hydro's revenue requirements applications. There is no determination required by the Commission Panel regarding Site C expenditures in this proceeding. However, the Commission Panel does note that Site C appears to be an attractive resource under a wide range of scenarios for the project's capital costs. In addition, this resource may be important given the growing limitations on alternatives that may be available to BC Hydro for new dispatchable capacity additions under anticipated government policy.

With respect to the Burrard issue, the Commission Panel is concerned by BC Hydro's lack of clarity regarding this issue. As noted in Section 3.3 of this Decision dealing with the load resource balance, the Commission Panel does not accept simply excluding the firm capability of Burrard from available supplies, until a formal application to retire the plant has been made by BC Hydro and accepted by the Commission. In the meantime, Commission Panel considers decisions about whether to replace the firm energy or capacity provided by the plant to be economic ones, not reliability ones, and therefore clearer economic justification will be required by BC Hydro in bringing forward resource plans to replace Burrard's energy or capacity.

The Commission Panel is also concerned with BC Hydro's analysis of the relative risks of Burrard repowering as compared to advancing ILM and further evidence will be required to support any future applications based on these arguments. The Commission Panel does not find that any of the immediate decisions before it in this application hinge on the issue of maintaining or repowering Burrard. The Commission Panel notes BC Hydro's commitment to study the costs of Burrard repowering as part of the 2007 Call Definition phase work subject to any changes in Provincial Government policy (Exhibit B-17-3, BCUC 4.451.4). The Commission Panel expects the Burrard issue to be dealt with more explicitly in the 2007 Call NSP and future IEP/LTAP applications.

The two portfolios that have the greatest number of required transmission reinforcements are the "Low Air Impacts without EE 3, 4 and 5" and the "Low Cost Without EE 3, 4 and 5" portfolios (Exhibit B-1C, Appendix H, Table H-1). These portfolios, requiring eight reinforcements each, do not include the effects of EE 3, EE4 or EE5. This observation demonstrates the importance of the forecast response to DSM initiatives for deferring transmission system reinforcements.

The Commission Panel is concerned that there was only one IEP portfolio constructed in response to the absence of the ILM project and, in particular, is concerned with the BCTC's starting assumption that the ILM project is in-service for October 2013 for the assessment of the transmission implications associated with the IEP portfolios. As discussed in other sections of this Decision, the challenges of securing the necessary permits and approvals for the ILM project are significant, and there is considerable risk that a projected October 2013 in-service date may not be realized. The next LTAP should identify responses to a delay in the October 2013 in-service date of the ILM project, including a prolonged delay.

The Commission Panel is concerned that the transmission implications identified in Appendix H of the Application are not based on the same transmission planning assumptions used in the NITS application, which drives BCTC's capital planning process. This difference in planning assumptions could result in transmission system reinforcements as identified by the NITS application review that are significantly different than the transmission system reinforcements identified in Appendix H of the Application. **The Commission Panel accepts the proposal described in Exhibit B-102 that BC Hydro will request BCTC to study the effects of the transmission planning assumptions related to Coastal Regional RMR generation, Interior Region Heritage resource dispatch and the treatment of intermittent resources, and that based on the outcome of these studies, BC Hydro may modify these planning assumptions as part of its NITS application.**

As part of these studies, the Commission Panel anticipates further consideration of BC Hydro's proposal not to designate Burrard as an RMR facility in the next NITS application. The use of Burrard as an RMR facility has the potential to defer many of the transmission reinforcements identified in Appendix H. Conversely, the use of MCR for the interior Heritage hydroelectric facilities in the NITS application results in a requirement for more transmission capacity as compared to the lower value of DGC used for the IEP portfolio evaluation and LTAP analysis.

The Commission Panel is also specifically concerned about the treatment of intermittent resources for the NITS application review. In situations where new or incremental transmission is required to access a collection of intermittent resources that have some geographical or fuel source diversity, it is not apparent that the transmission should be sized to the maximum aggregate MCR rating of the collection of intermittent resources. In some cases, a better economic outcome might be achieved if some amount of generation were to be stranded in exchange for avoiding additional transmission reinforcement expenditure. For situations involving a collection of diverse intermittent resources, especially when the output of the individual generation resources have a DGC rating that is 7.5 percent of the MCR, it is not apparent that the process by which BCTC evaluates the consequences of BC Hydro's NITS application contains enough economic or technical information concerning the dispatch of these resources to enable BCTC to identify the best economic outcome, even if it was directed to do so.

The Commission Panel concludes that it is very likely that the transmission reinforcements identified in Appendix H of the Application will not be consistent with the outcome of the NITS application review because of the differences in the transmission planning assumptions.

The Commission Panel encourages BCTC to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis and the NITS application review. The Commission Panel directs BC Hydro to provide a description of these planning assumptions in the next LTAP application. The description of the planning assumptions should address coastal capacity reserve requirements in the determination of coastal RMR capacity, including the dispatch of Burrard.

The Commission Panel is concerned that insufficient analysis is being done to make economic decisions regarding new transmission and transmission reinforcements. Therefore, the Commission Panel expects BC Hydro to include as part of the next LTAP application, a comparison of the use of MCR by other utilities in determining the need for new transmission and other transmission requirements for transmission paths that are used for aggregated transfers. The Commission Panel expects this comparison to include a proposal for making tradeoffs between the probability of stranding some amount of generation and incurring expenditures for transmission reinforcements to access collections of diverse intermittent resources with low DGC to MCR ratios.

5.0 RISKS AND UNCERTAINTIES

The Commission's Resource Planning Guidelines identify as an objective, the minimization of risks, and require that each resource be measured against the associated risks (Exhibit A2-21). In its 2006 IEP/LTAP filing and during the regulatory review proceeding, BC Hydro identified a number of risks that it considers in its resource planning. This Section examines BC Hydro's risk analysis.

In this Decision, the Commission Panel adopts BC Hydro's use of the word "risk" but notes that, from BC Hydro's perspective, these factors are actually uncertainties which, in turn, create risks for the ratepayers.

5.1 Gas and Electricity Price Forecast Risk

The IEP analyzes natural gas and electricity price risk using three natural gas price scenarios to represent a "plausible range of possible outcomes" (Exhibit B-1A, p. 3-15). The low scenario is the Confer Consulting Long Run Marginal Cost ("LRMC") case based on the view that technology is able to keep ahead of demand. The medium scenario is the Energy Information Administration ("EIA") 2005 Reference Case ("EIA 2005") with prices increasing at a relatively high rate as strong demand growth and cost of production increase with cumulative consumption. The high scenario is a BC Hydro-developed scenario ("High Gas"), which projects the highest 12-month historical average into the future; it "is not based on any model or analytics" (Exhibit B-1B, Appendix J, p. 4).

The scenario approach was used in order to minimize the risk of forecasting error and to show a range. BC Hydro considers the scenarios all plausible and does not assign any specific probability to each of them (T14:2217; BC Hydro Argument, p. 37). BC Hydro submits that the EIA 2005 forecast is an attempt to forecast market prices, while the Confer forecast is an attempt to forecast the marginal cost of natural gas (T14:2207). The IEP describes the High Gas scenario as "intended to form an upper bound for the natural gas price forecasts" (Exhibit B-1B, Appendix J, p. 5). During the proceeding, BC Hydro modified its position on the High Gas case and submits that "it was not intended to signify or represent any upper limit or bound in terms of where prices *could* go" (BC Hydro Argument, p. 36, emphasis in original).

The three natural gas price scenarios were used as key inputs to develop six electricity price forecasts, three of which assumed that gas-fired generation project owners earn a reasonable return on their full capital investment, and three that assume only 25 percent capital recovery. The IEP considers five of the resulting electricity price scenarios (Exhibit B-1A, pp. 3-16 to 3-17).

Two additional natural gas price forecasts were considered by BC Hydro but not used in the detailed IEP analysis. The EIA 2006 Reference case indicates a significant increase in the near term, and remains higher over the 20-year term, relative to the EIA 2005 forecast. The Natural Resources Canada ("NRCan") study, introduced by BC Hydro during the proceeding, shows prices that are higher than the LRMC and EIA 2005 cases (Exhibit B-25, Direct Testimony of David Ince; Exhibit A).

The validity of the High Gas scenario was challenged by a number of participants. BC Hydro defended its methodology by stating that it is based on "real market data" but conceded that it could not be called a model (T13:1954). BC Hydro had incorporated a scarcity premium into the High Gas case because it submits that a natural gas scarcity premium may be here to stay (T13:1946-51; BC Hydro Argument, pp. 36-37).

BCOAPO submits that the scarcity premium seen in mid-2006 was likely due more to volatility than a sudden and persistent rise in the long-term trend of natural gas prices (BCOAPO Argument, para. 58). Terasen submits that BC Hydro does not provide adequate justification as to why such high gas prices would be sustained over an extended period of time, and that real market behaviour and outcomes include cyclicality of higher and lower prices (Terasen Argument, para. 21).

BC Hydro's use of the scenarios was also examined during the proceeding. BC Hydro's Chief Risk Officer explained that in order to minimize regret risk, it looks for "a portfolio that performs well over a range of scenarios" (T14:2211-12). BC Hydro defends its reliance on the High Gas scenario by citing the skewed risk distribution (T14:2208) and submits that it is reasonable to take steps to avoid exposure to the High Gas scenario (BC Hydro Argument, p. 38). When asked about the probability of actual gas prices being below the High Gas scenario, BC Hydro did not submit that the High Gas case was likely, but only that "there's a range of events and possibilities…that could cause the high gas case to persist for quite a period" (T14:2208-09).

Terasen submits that the High Gas scenario should only be used as "a stress test" in performing economic evaluations, and that it should be given a lesser weight than the other forecasts (Terasen Argument, para. 22, 25). BCOAPO also submits that the High Gas scenario should, if anything, be given less weight than the EIA 2005 and LRMC scenarios which consider long-term demand and supply modeling (BCOAPO Argument, para. 55, 59).

Commission Determination

The Commission Panel accepts BC Hydro's submission that using three forecasts is preferable to relying on an average of the forecasts, but finds the 'equal weighting' argument unhelpful. BC Hydro did not provide evidence that the three scenarios are equally probable, nor is it logical to give the three scenarios equal weightings. The low and high cases are not really 'forecasts' because the case for the underlying assumptions was not established. As BC Hydro noted, the LRMC case is a cost forecast rather than a price forecast. Similarly, BC Hydro is not 'forecasting' that the events that would lead to the High Gas case will occur; it has simply projected the highest 12-month historical average into the future.

The Commission Panel considers the use of High Gas as a scenario for testing portfolio risk to be valid but, considering the lack of analysis underlying the High Gas case, is concerned that BC Hydro may be giving it undeserved weight in the final selection of resource options.

Although the methodology used to produce the electricity price forecasts was not challenged, to extent that there is an issue with unwarranted concern about High Gas, the Commission Panel's concern extends to electricity price scenarios based on High Gas.

5.2 Market Exposure Risk

Different resource portfolios can have different kinds and levels of exposure to changing market prices. BC Hydro's current exposure to natural gas and electricity commodity markets is comprised of the gas requirements for Burrard and the Island Co-generation Project ("ICP"), and any market electricity purchases. BC Hydro submits that its exposure to natural gas and electricity commodity markets in a critical water year is currently 18 percent, most of which is attributable to the 6,100 GW.h of firm energy from Burrard, plus another 1,900 GW.h from ICP and 2,500 GW.h from its non-firm/market purchase allowance. The latter may include domestic non-firm energy indexed to market prices, which BC Hydro expects to increasingly come from non-gas generation as the F2006 Call projects commence operations (Exhibit B17-3, BCUC 4.430.5.4, pp. 11-12).

In the Application, BC Hydro describes the risks of relying on the market for supply over the longer term as potentially manageable risks that need to be considered in any evaluation of market supply (Exhibit B-1A, p. 3-20). However, during the proceeding BC Hydro submitted that, although it does not have a target for market exposure, it believes that 18 percent is "too high" (Exhibit B-36, pp. 3-4; Exhibit B-17-3, BCUC 4.430.5.4, p.11; T13:1923-26). Therefore, it plans to replace the imports in the 2,500 GW.h market allowance with fixed contract, domestic non-firm energy resulting from the F2006 and later Calls (Exhibit B17-3, BCUC 4.430.5.4, pp. 11-12).

BC Hydro's actual exposure to the markets became clearer during the proceeding when BC Hydro submitted that, while its market exposure in a critical water year is currently 18 percent, under average water conditions it would be just 10-11 percent (T15:2273-74). BC Hydro provided further evidence of its market exposure under normalized weather and water inflow conditions for the 2006 Mid-load forecast, confirming the 18 percent exposure with critical water and 12 percent with average water (Exhibit B-72).

If BC Hydro's estimated market exposure is further reduced by the full 1,400 GW.h/yr of non-firm energy acquired in the F2006 Call (as discussed in Exhibit B17-3, BCUC 4.430.5.4), BC Hydro's estimated market exposure would decline to 16 percent and 9 percent under critical and average water conditions, respectively.

There are three potential types of risk associated with market exposure: supply risk, transmission risk and price risk. BC Hydro did not submit that it was concerned about an undersupply of natural gas in B.C. With respect to electricity supply risk, BC Hydro conceded that "there will always be a spot market, there will always be the opportunity to buy something somewhere at whatever price was available" (T8:892). BC Hydro raised, but then discounted, the political risk that U.S. would withhold supply to BC Hydro and agreed with BCOAPO's counsel that "Canada is massively a net exporter of energy to the [U.S.]" and that political inter-jurisdictional risk is not a large reason for self-sufficiency (T7:670-71).

BC Hydro submits that, in other North American jurisdictions, the trend is to securing more fixed price/term supply (Exhibit B-36, p. 4; BC Hydro Argument, pp. 39-42), and notes that other utilities have "significantly reduced their exposure to spot markets" and thus "drastically reduced their exposure to reliability risks" (T13:1934). BC Hydro submits that physical supply security is clearly the focus in the U.S., and that most of the states are taking significant steps to assure resource adequacy (T13:1938-39). When asked to provide more specific information about the move toward more fixed price/term supply, BC Hydro provided four examples of proposals, or efforts, to reduce market reliance but submitted that a comprehensive response would require a fairly complex and subjective undertaking which would include a study to determine each utilities' risk exposure and risk measurement techniques (Exhibit B-148).

A second component of market exposure is the risk that, even if sufficient electricity is available, transmission constraints may impede its delivery (T7:671). The IEP states that significant investment is required to move additional blocks of electricity between jurisdictions in western North America on a firm basis (Exhibit B-1A, p. 3-25). The IEP describes a number of initiatives and proposed projects intended to improve the regional transmission system, but expects bottlenecks to persist in the near-term (Exhibit B-1A, pp. 3-24 to 3-29).

The third risk associated with market exposure is the price risk associated with both the natural gas to run Burrard and ICP, and market electricity purchases. In many cases, BC Hydro can choose between purchasing natural gas or electricity and thereby avoid the more costly market. The IEP indicates that the much-advertised demand/supply “gap”, whereby BC Hydro has been a net importer in recent years, has occurred because “market purchases were economic to serve domestic requirements when compared to greater use of Burrard or greater drawdown of major reservoirs” (Exhibit B-1A, p. 3-7). In other words, BC Hydro chose to import electricity because the electricity market was more economic than the natural gas market especially given an 11,500 kJ/kW.h heat rate at Burrard.

Market price risk must be weighed against the cost of securing firm long-term electricity and/or gas. Only under the High Gas scenario is the F2006 Call fixed-price energy cheaper than projected market prices over the next 20 years (Exhibit B17-3, BCUC 4.444.1; BCOAPO Argument, para. 19). The portfolios with 3,000 or 6,000 GW.h/yr of market purchases are both cheaper and less sensitive to gas price forecasts than other scenarios (Exhibit B17-3, BCUC 4.430.5.4; BCOAPO Argument, para. 65).

BCOAPO submits that price volatility can be managed through both financial means and physical dispatch of resources, and supports BC Hydro’s pursuit of additional dispatchable capacity resources so that it can reduce energy purchases during high price periods, and take advantage of volatility to increase trade revenue (BCOAPO Argument, para. 66).

Terasen supports BC Hydro’s plans to reduce exposure to short-term commodity risk where the purpose is to achieve security of supply but notes that BC Hydro’s customers are substantially sheltered from market volatility because of BC Hydro’s level of exposure and because of its deferral accounts (Terasen Argument, para. 14-17).

CEC generally agrees that BC Hydro should reduce reliance on the electricity market but submits that the most cost-effective resource options should remain available to customers (CEC Argument, p. 56). CEC submits that spot market prices can frequently be below the cost of firm domestic supply and that there may be times where self-sufficiency is detrimental to customers' interests (CEC Argument, pp. 56, 57). CEC further submits that, as BC Hydro moves away from the market, there is a risk that trade income may be lost to customers (CEC Argument, pp. 77-78).

As noted above, BC Hydro has been a net importer in recent years because imports have been a cost-effective resource. During the proceeding an issue arose regarding to what extent it really was importing, and whether the data produced by BC Hydro or the data from the National Energy Board ("NEB") and StatsCan should be relied upon. BC Hydro submits that reconciliation of the data sets is neither warranted nor possible (Exhibit B10-3, SCCBC 1.26.6; T15:2244).

SCCBC submits that, given the great significance the IEP attributes to the ongoing state of B.C.'s import/export of electricity, it is "undesirable for BC Hydro to maintain non-transparent control over the data" (SCCBC Argument, pp. 34-35). BC Hydro submits that any information obtained would not justify the time and expense required (BC Hydro Reply, p. 55).

Commission Determination

The Commission Panel finds that the discussions about market exposure during the hearing were often confusing and unhelpful. BC Hydro and Intervenors frequently shifted between concerns about market exposure and security of supply, without making an adequate distinction between the two issues. The Commission Panel notes that supplies can be secure while prices vary. For example, there was no debate about the security of natural gas supply, although market prices can vary. Similarly, electricity imports are frequently equated with market purchases, although it may be possible to fix import prices through contracts of various duration. On the other hand, the price of certain volumes of non-firm purchases from domestic producers is indexed to market electricity prices. The Commission Panel expects BC Hydro to be more careful and consistent in its analysis of market exposure and security of supply issues.

The Commission Panel also finds BC Hydro's characterization of the level of market exposure unhelpful. In response to an information request, BC Hydro acknowledged that it had included the entire non-firm / market allowance in its calculation of market exposure, despite the fact that some of that allowance would be met through non-firm purchases at fixed prices from the F2006 Call (Exhibit B17-3, BCUC 4.430.5.4). The Commission Panel also notes there are different kinds of market exposure. For example, the exposure due to Burrard is fundamentally different from the exposure due to ICP, which is associated with a co-generation load, or the portion of the non-firm/market allowance that is met from market purchases. Burrard can be displaced by excess hydroelectric generation in high water years. Further, Burrard represents an exposure to the spread between gas and electricity prices, rather than an exposure to absolute electricity prices. Given these distinctions, the Commission Panel finds that aggregation of all types of resources with some exposure to market prices into a single category and comparing that to total resources is a wholly inadequate way to characterize market exposure risk. A more sophisticated approach, which BC Hydro already performs in its portfolio analysis, is to assess the sensitivity of the portfolios to changes in market prices under different water conditions. Such an approach would provide a more helpful understanding of the full risk profile.

The Commission Panel accepts in Section 3.2.1.1 of this Decision that for reliability purposes BC Hydro has to plan its system for critical water conditions. However, in the context of risk management, the "fuel risk" associated with critical water should not be overstated. BC Hydro has accounted for the risk of low water when it calculates its 18 percent market exposure. Therefore, even in low water years, 82 percent of BC Hydro's supply is free of market exposure. And, to the extent that market exposure occurs, it is primarily to either natural gas prices for Burrard and ICP or to the electricity spot prices, but rarely to both markets.

BC Hydro submits that it is locking in price and supply because physical supply risk is unacceptable. However, there is insufficient evidence of a supply risk. BC Hydro did not provide evidence that it has ever encountered market supply problems, and recent developments and trends in the market region support a scenario of reduced supply risk for the region's utilities, including BC Hydro.

Regarding transmission risk, the evidence shows that there are both constraints and potential improvements. Moreover, as discussed in Section 5.5, the transmission risk is not limited to electricity imports.

Therefore the market risk issue for BC Hydro is primarily one of price. The issue is not one of balancing the risk that "the lights go out" with the risk that you pay too much to keep the lights on (BC Hydro Argument, p. 45) but rather balancing the certain costs of firm long-term contracts against the uncertain costs of future market purchases. The Commission Panel agrees with BC Hydro that in order to minimize regret risk, it should look for a portfolio that performs well over a range of scenarios. However, it appears that rather than following that criterion, BC Hydro has placed undue weight on its objective of reducing market exposure despite its submissions that the portfolios with 3,000 or 6,000 GW.h/yr of market purchases are both cheaper and less sensitive to gas price forecasts than other scenarios.

The Commission Panel notes that BC Hydro's claim that its market exposure is "too high" was a late introduction to its evidence and that it is not grounded in the planning objectives, nor even reflected in the attributes. It is also not supported by sufficient analysis of the risks involved in reducing market exposure. Given that there may be costs to reducing market exposure and that there are also potential benefits from some market exposure, there will be an optimal range of exposure to markets. BC Hydro's inability to articulate an optimal range for its exposure is troubling.

The Commission Panel does not find BC Hydro's evidence regarding other North American jurisdictions particularly compelling. The evidence lacked a clear and consistent definition of market exposure, making comparisons suspect. In addition, the incremental portfolio decisions of other jurisdictions must be interpreted in light of their existing portfolios. Jurisdictions that have been heavily reliant on a particular resource may be reducing risk by decreasing exposure to that resource. BC Hydro is not, and has never been, heavily reliant on natural gas and therefore its risk might not decrease if it reduces its market exposure. For BC Hydro, natural gas generation provides some diversification from its predominately hydroelectric system.

If BC Hydro is required by the Province to eliminate market exposure (an outcome that is not necessarily synonymous with security of supply), it will become very important for BC Hydro to manage the financial implications and unintended consequences of such a policy, one of which may be becoming an exporter of surplus clean, expensive electricity at low spot market prices.

Regarding net import data, the Commission Panel finds that, given BC Hydro's goal of becoming less reliant on imports, and the Throne Speech's indications of a policy of self-sufficiency, it is increasingly important that the level of net imports be accurately established. Therefore, BC Hydro should reconcile its data with the NEB/StatsCan data.

5.3 GHG and Other Environmental Risks

The IEP describes recent federal and provincial efforts to streamline the environmental assessment process for energy projects, and lists a number of Provincial subsidy initiatives for eligible wind, hydroelectric, and solar projects (Exhibit B-1A, pp. 3-43 to 3-46). Despite these developments, BC Hydro submits that environmental and social issues have the potential to delay and add costs in the future through increasingly stringent regulation and public expectations (Exhibit B-1A, pp. 3-46 to 3-47).

The IEP recognizes the potential for government-imposed costs associated with GHG policy (Exhibit B-1A, Section 3.4). Due to the uncertainty regarding future GHG emissions regulations, BC Hydro uses five GHG cost scenarios to account for certain risk factors over the 20-year planning period (Exhibit B-1A, pp. 3-41 to 3-43). Since the oral phase of the proceeding, the Province has indicated in its Throne Speech that it will implement a series of successively tighter mandatory targets for GHG reductions (Exhibit A2-26).

Intervenors generally accepted BC Hydro's approach for managing GHG risk. The only significant issue was that of risk allocation between the utility and the IPPs. BCOAPO submits that IPPs should not be given the option of transferring to BC Hydro the risk of escalating GHG costs, but should bear that risk themselves (BCOAPO Argument, para. 76). CEC submits that the GHG cost risks are substantial and that BC Hydro should not be taking on risk in this regard (CEC Argument, p. 76).

BCOAPO further submits that government policy developments may create a risk of stranded investments in GHG-emitting generation facilities, and that the financial and regulatory risk should be borne by the developer (BCOAPO Argument, para. 89, 97).

Commission Determination

The Commission Panel finds that there are too many outstanding issues resulting from changing government policy to draw conclusions about BC Hydro's approach to GHG risks at this time. The Commission expects GHG risks to be addressed more fully in the next LTAP proceeding.

The Commission Panel considers the allocation of risk associated with GHG costs and stranded investments to be a subject for the 2007 Call NSP.

5.4 Government Policy and First Nations Risk

The IEP lists some recent regulatory and policy developments and trends at the federal and provincial levels that "could be significant" including likely more stringent air emissions standards, possible water conservation-inducing rate structures, and tougher wildlife standards (Exhibit B-1A, p. 3-46). During the proceeding an additional government policy risk developed, as the Provincial Government promoted a policy of "self sufficiency" by 2016 (Exhibit A2-26; Exhibit B-36, Attachment 1).

BC Hydro emphasized the need to maintain flexibility in its planning and to have an IEP that could accommodate changes in government policy (T7:801, 850, 881-83), positions that were supported by many Intervenors.

Some Intervenors identified increased risks associated with a requirement for self sufficiency. The JIESC submits that "the shortage of competition concern has been made worse by the self sufficiency requirement which effectively rules out bids from resources in nearby jurisdictions" (JIESC Argument, p. 12). BCOAPO submits that if elements of the Throne Speech become compulsory legislated measures, there is a risk that BC Hydro will depend on an array of intermittent resources and be short of incremental firm capacity (BCOAPO Argument, para. 89). BCOAPO also submits that "even if the policy objective were a sound one (which is entirely unclear), BC Hydro is currently in a poor position to pursue self sufficiency" (BCOAPO Argument, p. 7).

BC Hydro appears to be in agreement with BCOAPO and submits that it desperately needs additional capacity (T15:2247; T22:3402), but that "renewables offer limited dependable capacity and the generation potential is uncertain" (Exhibit B-1A, p. 3-9).

BC Hydro submits that its objective is security of supply, which is different than the Province's self sufficiency goal. For BC Hydro and its customers, having enough energy is more important than self sufficiency (T8:901-02). However, BC Hydro submits that the LTAP, with its underpinnings of security of supply, is clearly aligned with the Province's commitment to self-sufficiency and enables BC Hydro to shift to self-sufficiency (BC Hydro Reply, p. 49).

First Nations are affected to some degree by most of the resources in BC Hydro's portfolios, as virtually all of B.C. is under land claim (Exhibit B-1A, p. 3-48). The IEP identifies some of the risks that BC Hydro and IPPs face, including inability to access facilities for maintenance or other purposes, injunctions, invalid permits, damages or compensation (Exhibit B-1A, p. 3-47). The risks associated with First Nations received little attention during the proceeding.

Commission Determination

The Commission Panel agrees that the IEP's flexibility will help BC Hydro mitigate the risk of government policy changes, including the developing self-sufficiency requirement. The 2002 Energy Plan limited BC Hydro's options for developing new resources, and recent government policy changes further constrain its options for achieving security of supply. Self-sufficiency limits BC Hydro’s use of cost-effective firm resources from nearby jurisdictions, while the carbon sequestration and clean energy requirements restrict the types of local generation that can be considered. Given these developments, BC Hydro will be challenged in its efforts to achieve security of supply in a cost-effective manner.

However, as discussed in Section 3.3, the Commission Panel notes that BC Hydro is currently at or near a supply/demand balance, and that the government’s self-sufficiency policy applies to the province, not just to BC Hydro, and is for 2016. Therefore, BC Hydro has some time to adjust to self-sufficiency if it becomes a legislated requirement. The Commission Panel encourages BC Hydro to maintain flexibility in order to accommodate additional government policy changes.

BC Hydro has committed to incorporating the Throne Speech and the 2007 Energy Plan into its next LTAP. BC Hydro’s plans for achieving security of supply in a cost-effective manner while incorporating government requirements will be assessed during the next LTAP regulatory review.

The Commission Panel finds that BC Hydro may not have sufficiently assessed the risks associated with the First Nations affected by its resource options. BC Hydro referred to ILM as a “slam dunk” without having even a rough idea of the number of First Nations affected because it sees “huge uncertainty in terms of the ability to develop projects close to the Lower Mainland” (T8:1091). There is a marked difference between the attention paid to maintaining a “social licence” in Port Moody and BC Hydro’s evidence regarding First Nations.

5.5 Deliverability Risk of the Options

Deliverability risk concerns BC Hydro’s ability to cost-effectively acquire new DSM, IPP and Resource Smart resources to fill any load/resource gap, and the availability of adequate transmission to deliver the energy to load centres. BC Hydro submits that the IEP is flexible enough to adjust to unexpected cost increases or deliverability problems (T10:1372) and that it has contingency plans to deal with a transmission delay (BC Hydro Argument, pp. 60-61).

DSM

BC Hydro submits that its existing EE2 and LD2 programs are delivering the expected energy savings. The planned programs will be subject to an extensive design phase and pre-implementation phase regulatory review. If forecasts of cost-effective volumes of DSM change, the LTAP will be updated and the relative amounts of acquisitions from other sources will be increased or decreased (T8:1066-70; BC Hydro Argument, p. 57). BC Hydro acknowledged the difficulty of forecasting DSM costs (T11:1573).

Intervenors generally agreed with BC Hydro that DSM is a relatively low risk option for meeting future needs.

IPP Projects

IPP deliverability risk comprises not only cost and timing risks, but also the risk of attrition. BC Hydro recognized that the 2003 CFT had a very high attrition rate, with only two of 16 projects completed on time, representing only 40 GW.h/yr of the 1800 GW.h/yr acquired (T8:925-26), and stated that it is attempting to manage the IPP deliverability risk through call terms, performance penalties, and attrition allowances (T21:3241-42; Exhibit B17-3, BCUC 4.430.4). BC Hydro also submitted that it may try to reduce attrition risk by requiring developers of large projects to be further along in the development process before awarding an EPA (T21:3241-42).

BC Hydro has assumed a 23 percent attrition rate for the F2006 Call. The common challenges of financing and growing construction costs are expected to affect some of the projects. In addition, the Province's recent decision to require 100 percent carbon sequestration for coal projects (Exhibit A2-26) presents development challenges for two large F2006 Call projects.

Despite the high IPP attrition rate, BC Hydro is less concerned about the development risk of specific IPP projects than it is with its own Resource Smart projects, explaining that “it’s really up to the developers of those projects to make the [risk] assessment” (T10:1307), and that “developers are usually optimistic” (T9:1118-19). BC Hydro submitted that developers and BC Hydro face similar permitting challenges but that developers have more choice among projects and sites (T10:1308) because the Province has restricted BC Hydro’s ability to develop new projects.

CEC submits that BC Hydro has not addressed the potential for price risk related to the supply of power from IPPs, and that this is a significant risk that should be acknowledged (CEC Argument, p. 77).

Intervenors also addressed the issue of which party should assume the gas price risk. The JIESC submits that if proponents of gas-fired projects are not prepared to take the fuel price risk, it is an indication of the comparative risks of natural gas, and the JIESC “strongly questions why the customers should take the fuel price risk of a gas plant in these circumstances” (JIESC Argument, p. 9).

BCOAPO submits that BC Hydro is in a better position to take on the gas price risk because of its ability to use hedging, both physical and financial, and other strategies to reduce exposure to price spikes (BCOAPO Argument, para. 94). However, BCOAPO also submits that if BC Hydro assumes the gas price risk then the value of IPP development of large gas-fuelled facilities is dubious because little would be achieved in terms of risk transfer away from the utility, while costs would escalate (BCOAPO Argument, para. 95).

<u>Resource Smart</u>

Resource Smart projects do not face the financing challenges that IPP projects encounter, nor do they face all of the same development risks as greenfield projects. Also, as BC Hydro is in control of its own Resource Smart projects, it is better able to manage their timing. However, BC Hydro adopts a cautious approach when considering the development risks of potential Resource Smart projects such as Burrard, because it fears that public and political opposition might overcome logic (T10:1302, 1393). BC Hydro also recognized the execution risk associated with Resource Smart projects (T8:992-93) and submitted that it has taken steps to address the accuracy of the cost estimates (T18:2674-77).

Intervenors were generally supportive of Resource Smart projects and in some cases urged BC Hydro to develop them earlier than planned (BCOAPO Argument, para. 53, 66, 101; JIESC Argument, p. 17; CEC Argument, p. 55).

Transmission Constraints Risk

In addition to the transmission risks associated with electricity imports discussed earlier in Section 5.2, there are physical constraints on delivery of domestic power (Exhibit B-1A, p. 3-5). Successful DSM programs will reduce the need for additional transmission within the province, but Resource Smart and new IPP projects will increase transmission requirements, unless they are sited close to the Lower Mainland and Vancouver Island loads.

BC Hydro submitted that ILM is needed for Revelstoke Unit 6 or Mica Unit 5 (T10:1354) as well as for the IPP projects that emerge from the 2007 and 2009 Calls (T10:1367). BC Hydro also submitted that ILM is a high risk development project, assuming that about 10 First Nations would be affected, and that the development risk would change "dramatically" if that number were higher (T10:1337). BC Hydro later corrected the figure to something more than 50 (T10:1345).

BCTC acknowledges the risk associated with ILM, but claims that ILM will be required at some time (BCTC Argument, para. 11). The timing will be affected by the generation choices made in the LTAP and the CRPs and the decisions surrounding the repowering of Burrard, but ultimately the ILM reinforcement is necessary (BCTC Argument, para. 13). BCTC claims there is little to be gained by making generation option decisions in an effort to defer ILM transmission reinforcement (BCTC Argument, para. 21).

CEC acknowledges the risk associated with transmission projects being completed on time (CEC Argument, p. 76), while the JIESC discourages pursuing Burrard repowering as a means to defer the ILM transmission reinforcement because it could give parties opposed to ILM a false sense of security that there was a realistic possibility of an alternative, and thereby complicate the permitting and approval of the ILM project (JIESC Argument, p. 16).

IPPBC expresses some concerns that the issue of transmission intertie upgrading with Alberta and the United States was not adequately canvassed in this hearing, and submits these upgrades should have been considered in this hearing because of their effect on realizing trade benefits associated with projects such as Revelstoke Unit 5 (IPPBC Argument, p. 32).

BC Hydro points out that replacement of generation options located in one major transmission region with generation options located in another major transmission region could have a significant impact on BCTC's transmission capital plans (BC Hydro Reply, p. 69).

Commission Determination

The Commission's concerns about DSM deliverability are described in Section 6.1.2.

The Commission Panel concludes that there is significant cost and development risk, particularly with IPP projects. BC Hydro appears to give less consideration to IPP development risk relative to its own projects, and may be underestimating the former.

In order to mitigate risks and ensure that cost-effective resources are acquired, BC Hydro needs to be able to readily compare DSM, IPP and Resource Smart resources in order to adjust the amounts acquired from each option if unexpected costs or delays develop. Although BC Hydro submits that its IEP is flexible enough to adjust the resource mix if cost or deliverability problems materialize, it did not do so when the F2006 Call resulted in higher than expected prices; instead, it increased the Call volume.

The Commission Panel notes BCOAPO's submission that if BC Hydro assumes the gas price risk then the value of IPP development of large gas-fuelled facilities is dubious because little would be achieved in terms of risk transfer away from the utility, but will leave the allocation of gas cost risk as an issue for the call negotiations.

The Commission Panel is concerned that BC Hydro may have underestimated transmission constraints risk in its IEP. If the IPP and Resource Smart options depend on ILM, and if BC Hydro's assessment of ILM's development risk is something "dramatically" different than "high", then BC Hydro's plans appear to be at risk. Although BC Hydro has contingency plans to address an ILM delay, it should ensure that its efforts to develop the components of the contingency plans are commensurate with the risks of an ILM delay.

The Commission Panel observes that there was only one IEP portfolio that did not have ILM as a component (Exhibit B-1C, Appendix H, Table H-1). From this perspective, the Commission Panel believes the arguments that establish the eventual need for ILM are persuasive. However, given the permitting and execution risks associated with the ILM project, a single IEP portfolio and reliance upon the continued operation of Burrard appear to be inadequate contingency plans in the event of a prolonged delay in the implementation of the ILM project.

6.0 LONG-TERM ACQUISITION PLAN

BC Hydro states that the LTAP's action items are as follows:

- to target 5,900 GW.h/yr of new DSM resources by F2015;
- to enter into contracts with IPPs for new incremental electricity supply since approximately 5,100 GW.h/yr is required from IPPs in F2015; and
- to develop its own Resource Smart capacity projects, such as Revelstoke Unit 5, to meet reliability requirements, augment the DSM and IPP supply contributions and maintain operational flexibility.

BC Hydro also states that at a high level, the LTAP also identifies BC Hydro's expected transmission requirements (BC Hydro Argument, pp. 5-6).

The Commission Panel notes that the 5,900 GW.h of DSM resources highlighted by BC Hydro above includes the expected savings from EE2 and LD2, which the Commission Panel has already included in the current load/resource balance discussed in Section 3 of this Decision.

The tables below summarize the Commission Panel's understanding of BC Hydro's needs assessment and its proposed significant resources and acquisitions. The remainder of this Section reviews the proposed actions and makes any determinations that are necessary. The Commission Panel notes that the orders sought by BC Hydro in its Application deal primarily with the approval of funds for the Definition phase of work associated with the above actions. BC Hydro has not sought approval of specific acquisition targets at this time and this Decision does not make any determinations regarding specific targets. These will need to be addressed by BC Hydro in the approval of further expenditures or any EPAs related to the above actions.

BC Hydro Firm Energy Requirements and Plans (GW.h) by F2015 Based on Mid-Load Forecast

Total Identified Need / Substitution	
Minimum Firm Energy Required for Reliability Planning Purposes (See Section 3.3.3 Determinations)	1,800
Possible Replacement of Burrard	6,100
Possible Substitution of Additional Non-Firm Energy within the Non-Firm/Market Allowance	1,500
Total Potential Energy Requirement	1,800 – 9,400
Significant Proposed Energy Additions	
EE3. EE4, and EE5*	3,300
2007 Call	5,000
Additional Non-Firm Supply	1,500
Total Proposed Energy Additions	9,800

* The savings attributable to EE2 and LD2 are reflected in the existing load/resource balance and the minimum firm energy required for reliability planning purposes.

BC Hydro Capacity Requirements and Plans (MW) by F2015 Based on Mid-Load Forecast

Total Identified Need / Substitution	
Minimum Capacity Required for Reliability Planning Purposes (See Section 3.3.3 Determinations)*	600
Possible Replacement of Burrard**	1,000
Total Potential Capacity Requirement	600 - 1,600
Significant Proposed Capacity Additions	
EE3, EE4, and EE5***	400
2007 Call	400
Resource Smart	1,000
Total Proposed Capacity Additions	1,800

* Based on reserve requirements outlined in Exhibit B-55. These are likely understated and this issue will need to be addressed by BC Hydro in future filings.

** BC Hydro's estimate based on rounding of capacity from Heritage Thermal resources.

*** The savings attributable to EE2 and LD2 are reflected in the existing load/resource balance and the minimum capacity required for reliability planning purposes.

6.1 Demand Side Management

6.1.1 EE3, EE4 and EE5

In order to fill a portion of the load resource gap BC Hydro plans to undertake three new Energy Efficiency initiatives known as EE3, EE4 and EE5.

Table 8.1 of BC Hydro's Amended LTAP summarizes Resource Requirements and Supply Plans and shows load increases of between 18,800 and 26,900 GW.h/yr for the 20-year period with the Mid Load Forecast showing an increase of 22,600 GW.h or an average annual increase of 1.7 percent. BC Hydro forecasts that DSM programs will provide 9,600 GW.h/yr of energy savings (including losses) in the same period, which represents 42 percent of the load increase in the Mid Load Forecast.

The Throne Speech suggests that the Provincial Government policy may put even greater reliance on DSM and BC Hydro's Power Smart program as a resource (Exhibit A2-26).

BC Hydro stated that the objective for its 2007 CPR is to estimate potential energy and capacity savings over the next 20 years among its customers by updating the base year conditions to reflect the market changes since the 2002 CPR; by adding further resolution to the technology based opportunities for BC Hydro; by extending the study period out to 2026 and by expanding the scope of opportunity beyond technology to a more comprehensive understanding of the potential associated with behaviour and lifestyle. The 2007 CPR will also review electricity savings potential associated with alternative energy and fuel switching (Exhibit B-126).

Energy Efficiency 3

BC Hydro defines the Most Likely Achievable Scenario as the portion of savings identified in the Economic Potential that are considered to provide a high confidence level that BC Hydro can achieve these savings through reasonable actions that most of its customers would expect it to take (Exhibit B-1B, Appendix F, p. 6-3).

BC Hydro states that its 2002 CPR Likely Achievable Scenario identified potential savings beyond those that have been committed in EE2 and that EE3 is currently planned to be a continuation of EE2 over the five-year period from F2012/13 to F2016/17. The EE3 information presented in the IEP is described as a "Feasibility Study".

BC Hydro stated that the technologies to be employed in EE3 are similar to those in EE2 and that the program is projected to have ultimate annual energy savings of 2,576 GW.h with utility direct capital costs of $325 million and customer costs of $333 million with the TRC for EE3 anticipated to be $37/MW.h (Exhibit B-7, Database, p. 1).

Energy Efficiency 4

BC Hydro defines the Upper Achievable Scenario as the portion of savings identified in the Economic Potential that are considered to be achievable by BC Hydro taking a more aggressive approach to electricity conservation and being supported through actions of governments at all levels (Exhibit B-1B, Appendix F, p. 6-3).

BC Hydro states that the Upper Achievable Scenario of the 2002 CPR identified additional savings beyond EE2 and EE3 including mandated energy efficiency and aggressive promotion of new technologies. The program is planned to take place from 2009/10 to 2023/24. In the IEP the program was described as a "Pre-feasibility" study.

BC Hydro stated that EE4 is anticipated to achieve ultimate annual energy savings of 2,534 GW.h at a utility direct capital cost of $360 million and customer costs of $462 million producing a TRC of $45/MW.h (Exhibit B-7, Database, p. 2).

Energy Efficiency 5

EE5 is based on a very aggressive scenario, which captures half of the savings identified in the 2002 CPR between the EE4 and the Economic Scenario. Hence it projects energy savings beyond EE2, EE3 and EE4. EE5 is planned to take place from 2015/16 to 2023/24 and uses aggressive incentives, promotion and education to accelerate the adoption of new technologies followed by government regulation and legislation. EE5 is described as being a "Conceptual" study.

BC Hydro stated that EE5 is anticipated to achieve ultimate annual energy savings of 2,164 GW.h with a utility direct capital cost of $386 million and customer costs of $472 million producing a TRC of $65/MW.h (Exhibit B-7, Database, p. 3).

Since these programs are currently at study levels described variously as "feasibility, pre-feasibility, and conceptual", BC Hydro has requested a determination under Section 45(6.2)(b) of the UCA that expenditures of $1.7 million required to undertake and complete the Definition phase work of the three programs, including the completion of an updated CPR, are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro (BC Hydro Argument, p. 8).

No Intervenor opposed the order requested related to the $1.7 million.

The JIESC specifically supports the need to complete the 2007 CPR by the fall of 2007 (JIESC Argument, p. 10), while the SCCBC and Terasen specifically support the request related to the $1.7 million expenditure (SCCBC Argument, p. 11; Terasen Argument, p. 5).

Micro Hydro Load Displacement

BC Hydro requests a determination under Section 45(6.2)(b) of the UCA that expenditures of $0.8 million for the electricity savings associated with the Greater Vancouver Water District micro-hydro Load Displacement project are in the interest of persons within B.C. who receive, or may receive, service from BC Hydro (BC Hydro Argument, p. 8).

BC Hydro states that the project is demonstrably cost-effective and has a price of energy significantly below the 2003 Green Call reference Price. BC Hydro notes that neither Intervenors nor Commission counsel raised the project during the oral phase of the hearing (BC Hydro Reply, p. 11).

No Intervenor expressed a concern with the project in argument.

Commission Determination

BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that the $1.7 million expenditures required to undertake and complete the Definition phase work of EE3, EE4, and EE5 and the updated CPR are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07.

BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $0.8 million for the electricity savings associated with the Greater Vancouver Water District micro-hydro Load Displacement project are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07.

6.1.2 General DSM Planning Considerations

Future DSM activities are forecast to constitute a considerable component of the efforts to close the load/resource gap. BC Hydro intends to apply to implement EE3, EE4 and EE5 after the completion of the 2007 CPR and the Definition phase work for the three programs. This Section discusses some general planning considerations related to future DSM programs.

6.1.2.1 DSM Targets and Screening

The issue of the appropriate tests to evaluate DSM programs was considered in depth during BC Hydro's F05/F06 RRA proceeding, and Commission determinations at that time are discussed below.

The three tests used by BC Hydro are the Rate Impact Measure ("RIM"), Total Resource Cost ("TRC") and Utility Test. BC Hydro refers to the first two tests as the Non-Participants and All Ratepayers tests respectively. BC Hydro uses the TRC test as the primary screening tool, while the RIM test is used to assess the distributional impact. In applying the Utility Test BC Hydro employs a levelized value of 2.5 cents per kW.h in a manner that it described as a screen. This screen provides direction to planners to try to design their programs within the 2.5 cent guideline (T18:2731-32).

BC Hydro justified this guideline by noting that it is currently pursuing only 3,600 GW.h of energy savings. BC Hydro agrees that it could achieve more savings than the 3,600 GW.h target, and stated that given the constraint of the target, the 2.5 cent value was intended to put downward pressure on costs so that program planners did not invest more than they needed to in pursuing the targeted amount of energy (T18:2732-34).

The Commission Decision that accompanied BCUC Order No. G-96-04 related to BC Hydro's F05/F06 RRA denied BC Hydro's request for approval of the Power Smart 10-year Plan pursuant to Sections 45(6.1)(c) and 45(6.2) of the Act (Decision, p. 201). However, in the same Decision, the Commission approved all Power Smart expenditures in the REAP subject to exceptions with respect to the load displacement programs.

BC Hydro's revenue requirements for F07/F08 were subject to a NSP, which was approved by BCUC Order No. G-143-06. The NSA included an agreement on BC Hydro's DSM capital expenditures, as filed, for F2007 and F2008 (Order No. G-143-06, Appendix A, p. 8/45). BC Hydro states that no expansion of EE2 targets (for energy savings) or funding is contemplated (Exhibit B-1E, p. 8-16).

BC Hydro states that one of the purposes of the EE3, EE4 and EE5 Definition phase expenditures for which it requests approval, is the re-evaluation of the current 2.5 cent per kilowatt hour guideline as provided for in a reference to Exhibit C25-16 (BC Hydro Argument, p. 82). The information request response to which BC Hydro refers in Exhibit C25-16 also states that BC Hydro would not increase the utility cost guideline within the current 10-year plan just because of a particular increase in the avoided cost of energy.

In an exchange with the Chair during a discussion of the refrigerator buyback program, BC Hydro affirmed that its objective was not necessarily to deliver the most cost effective program, but rather to deliver the energy savings in a cost-effective manner (T12:1792).

ESVI submits that the 2007 Throne Speech states that the new energy plan will include new conservation targets to make B.C. self-sufficient within the decade ahead (ESVI Argument, p. 5).

The JIESC submits that BC Hydro should continue to use the 2.5 cents/kW.h criterion for testing existing programs until BC Hydro brings forward its application for EE3, EE4 and EE5, and the 2007 CPR (JIESC Argument, p. 11).

The BCOAPO supports BC Hydro in its development of all DSM resources that are cost effective and BC Hydro's decision to use the Utility Test as set out in the F05/F06 RRA Decision (BCOAPO Argument, p. 15).

The CEC does not believe that DSM programs should be limited by planning targets and submits that BC Hydro should put forward the full extent of cost-effective DSM that can be planned. CEC believes these concerns can be addressed during the next LTAP planning cycle (CEC Argument, p. 26). CEC submits that the pursuit of the lowest cost DSM projects makes business sense, and endorses any prioritization activity at BC Hydro aimed at optimizing value for money (CEC Argument, p. 29). CEC submits that BC Hydro should examine closely the merits of ramping up its DSM activities above and beyond those currently planned (CEC Argument, p. 31). Finally, CEC states that the proper test of the amount of DSM to pursue is all of the cost effective DSM savings BC Hydro can find to defer less cost effective investment (CEC Argument, p. 33).

IPPBC did not comment directly on the Utility Test and conservation target, but did provide extensive evidence on an “ROI” test, which is discussed in the following Section.

SCCBC filed the written expert evidence of Mr. John Plunkett (Exhibit C25-11), who also provided oral testimony at the hearing. Mr. Plunkett’s evidence was that by using a value of 2.5 cents/kW.h as the Utility Test, the acquisition of DSM resources was restricted (Exhibit C25-11, p. 4). While SCCBC welcomes BC Hydro’s commitment to re-evaluate the 2.5 cent guideline during the definition phase of EE3, EE4 and EE5, it submits that the Commission should determine that the use of the 2.5 cent guideline is not sufficiently justified and that in the development of EE3, EE4 and EE5 all cost effective DSM savings should be identified using the approved TRC and RIM tests set out in the F05/F06 RRA Decision (SCCBC Argument, p. 13).

Commission Determination

The Commission Panel is of the view that BC Hydro’s use of the three tests, and in particular the Utility tTest, is consistent with the directions provided in Order No. G-96-04. That Decision only specified that BC Hydro was to file tariffs for new Power Smart program where the TRC was less than 1.0 or the RIM less than 0.8.

However, the Commission Panel notes that, given the absence of approval of the DSM Ten Year Plan, or a specific planning target except as it might be inferred from the approvals in the two revenue requirement applications, no determination has been made as to the appropriate level of DSM savings and thus expenditures, beyond the four years already approved.

The Commission Panel notes the views of Intervenors on this issue, the recent Throne Speech, and the relative imminence of the CPR and subsequent filings. Therefore the Commission Panel expects that BC Hydro will address the issue of the appropriate DSM targets, if any, and the interrelationship of these targets with the appropriateness of each test, its threshold value, and the issue of cost effectiveness, at the earlier of filing of the application for EE3, EE4 or EE5.

6.1.2.2 The Return on Investment Test

In addition to the RIM, TRC and Utility tests, which the Commission has directed should be presented when DSM programs are reviewed (Order No. G-96-04, p. 192), the IPPBC presented the a Return on Investment ("ROI") test for consideration (Exhibit C18-5).

IPPBC characterizes the ROI as "roughly equivalent" to the TRC when applied to the total DSM Program and, when applied only to the utility costs and benefits, to be roughly equivalent to the RIM test (IPPBC Argument, p. 9). IPPBC asserts that the ROI "is a more generally known and understood metric in the business community, than the other metrics customarily used for DSM …" (IPPBC Argument, p. 9). When asked what other jurisdictions use the ROI as one of the major tests to determine the cost-effectiveness of DSM program, no examples were provided (Exhibit C-18-6, BCUC 1.1). IPPBC provided information on the economics of a hypothetical program (Exhibit C18-37).

BC Hydro witnesses stated that the use of the current three DSM tests had not impeded the pursuit of cost-effective DSM at the target levels being pursued (T18:2762).

No other Intervenor stated a preference to add the ROI metric to those already used by BC Hydro. However JIESC states that, while it had some sympathy for the IPPBC's ROI evidence, it believes this evidence was similar in nature to the Utility Test, which had been considered in the past (JIESC Argument, p. 11).

The CEC states that the IPPBC material did not fundamentally change anything regarding the merits of evaluation, and did not see any need for the Commission to change the tests employed (CEC Argument, p. 28).

Commission Determination

It is the Commission Panel's view that DSM programs sponsored by regulated cost-based utilities have certain unique attributes relative to more conventional investments, particularly in regard to the impacts on different ratepayers. It is the Commission Panel's view that this uniqueness is the motivation that has led other jurisdictions, and this Commission, to employ DSM- specific metrics in evaluating DSM programs. The Commission Panel notes the IPPBC's use of the phrase "customarily used for DSM" when discussing the existing three tests.

The Commission Panel views the three tests as well-known and transparent when viewed in the current regulatory context, and finds little merit in the argument that the ROI will make more sense to investors, since investors per se are not participants in utility- sponsored DSM programs. Similarly, the Commission Panel finds that adding the ROI as a DSM evaluation test would be of no merit, and may actually hinder transparency.

The Commission Panel suggests that, rather than pursuing the adoption of a DSM test not employed elsewhere, if IPPBC has continuing concerns regarding the impact on participants and non-participants, it should pursue these concerns in the context of the existing tests and the threshold values employed. The Commission Panel expects the IPPBC will have the opportunity to do so, at the latest, during the consideration of the implementation phase of EE3, EE4 and EE5.

6.1.2.3 Avoided Capacity Costs

BC Hydro testified that the cost of electricity used in the 2002 CPR did not include a value for avoided transmission and distribution capacity costs, but that it intends that the 2007 CPR will include a value for capacity, and that the long-run marginal cost is used to inform the economic screen used within the CPR (T19:2864-65).

BC Hydro stated that the range of avoided cost from previous studies was between $8 and $50/kW/yr (T19:2868; Exhibit B-101) and filed two studies, one of which was entitled “Long-run Incremental Cost Update- 2005/2006” dated December 1, 2004 (Exhibit B-100), which differentiated incremental cost of supply by customer class and by region.

Commission Determination

The Commission Panel notes that a value of $50/kW/yr is a significant amount when considered on a present value basis and that the range of $8 to $50 is substantial. Neither of the marginal cost studies was examined as part of this proceeding. However, the Commission Panel expects that, in its 2007 CPR, BC Hydro will employ the most recent data available on avoided transmission and distribution costs. The Commission Panel also expects that, if justifiable, BC Hydro will differentiate these costs by customer class and region, and discuss the usefulness of targeted DSM programs.

6.1.2.4 DSM Reporting Requirements

BC Hydro described the rationale for the format and content of its June 2005 Semi-Annual Demand Side Management report (T11:1574-75) and agreed that the reports could be enhanced in several ways (T12:1667-68).

Commission Determination

The Commission Panel directs BC Hydro to continue to file reports on DSM performance as described in Directive 69 included in Order No. G-96-04 and to file its Semi-Annual Demand Side Management Reports in the same format as the June 2005 Report with the following enhancements:

(1) Provide annual and cumulative totals since program inception;

(2) Express these values on a per unit basis; and

(3) Provide the benefit to cost ratios for the three DSM tests.

The Commission Panel also directs BC Hydro to continue to employ the three DSM tests in a manner consistent with Directive 70 included in Order No. G-96-04.

6.1.2.5 Natural Conservation

As noted in BC Hydro's Summary of DSM Evaluation Reports for Fiscal year 2004/05 (Exhibit A-37, BCUC 1.164.2, Attachment 1):

> "With the demand side, however, the greatest uncertainty is in determining the actual load impact. This uncertainty occurs in three general areas:
>
> What would have occurred if there were no program?
> What load impact did the program induce?
> How long will the load impact persist?"

BC Hydro further noted (lines 19-23) that:

> "…. Therefore for each program or end-use, a projection is required regarding the trends in efficiency improvements occurring naturally in British Columbia. Called the 'status quo' or natural conservation, this projection of natural conservation must be consistent with the load forecast. …"

BC Hydro further commented upon the importance of understanding the natural changes in efficiency over time as less efficient capital stock is replaced by more efficient capital stock (T10:1409).

As noted in Section 3.1, for the residential and commercial sectors BC Hydro uses end-use models to forecast load. BC Hydro testified that its Residential End-Use Energy Planning Systems model requires it to make many projections of factors such as appliance saturations and that its new models will require such projections to a similar extent (T11:1649).

BC Hydro noted that some of the appliance saturations were counterintuitive (T11:1647-49) and subsequently produced Exhibit B-74 to attempt to reconcile the counterintuitive values.

6.1.2.6 Impact of the Retail Price of Electricity

BC Hydro agreed that if it were operating with a negative margin, which was suggested to be $18 per MW.h and that if that negative margin had a significant impact on rate increases in the future, that it would also impact energy consumption. BC Hydro defined negative margin as occurring when the price it collects from a customer's run-off rate is less than the price of supplying that unit of energy. Furthermore BC Hydro agreed that if the negative margin was higher than $18 it would have an even greater impact on sales (T11:1612-15). BC Hydro further stated that the current load forecast did not take into specific account the impact of future BC Hydro rate increases on consumption (T11:1615).

BC Hydro agreed that real rate increases are an important factor in determining the impact on consumption (T11:1628) and that BC Hydro's load forecast assumes constant real prices for its electricity (T10:1485). Furthermore BC Hydro does not make planning-level forecasts of the changes in its retail prices over the 20-year load forecast horizon and/or incorporate such price forecasts into the load forecast (T11:1635).

BC Hydro stated that it has investigated its residential price elasticity and found significant, but low, values (T11:1633). BC Hydro further agreed that the values of price elasticity that it employed in its Monte Carlo studies are at the lower end of the range found in the literature (T12:1798). BC Hydro stated this was intuitively believable since when rates are relatively low, the price response will also be low (T12:1798-99). BC Hydro agreed that if electricity rates went up, elasticities would also rise (T12:1799).

When asked to consider the impact of the negative margin and future significant capital expenditures, BC Hydro agreed that it should perhaps consider using larger elasticities for the 20-year forecast (T12:1799-1800). BC Hydro further noted that the prices of in the most recent CFT had not been factored into their load forecasting (T12:1800).

As discussed in a previous Section, BC Hydro stated that GDP energy intensity does change over time and has decreased (Exhibit B-6, BCUC 1.253.5; Exhibit B-10, BCUC 2.402.1). This change in GDP intensity may be a form of natural conservation but it is not clear how its existence in the industrial and commercial load forecasts is made consistent with evaluation and monitoring efforts and the CPR.

6.1.2.7 Free Ridership

Free riders in DSM Pprograms are defined by BC Hydro as "… individuals or firms who undertake energy conservation measures under an incentive program, but would have done so without the incentive program" (T10:1487). BC Hydro agreed that the identification of free riders is an important issue in determining the impact of DSM programs on energy and capacity savings and determining cost-effectiveness (T11:1617).

To evaluate the Power Smart Partners Program for industrial and non-industrial customers BC Hydro employed a technique it called a Statistically Adjusted Engineering approach. This approach was asserted to be able to estimate the percentage of free ridership. For the non-industrial sector free ridership was estimated as ranging from 5 to 38 percent, while the industrial customers had a free ridership rate determined by survey to be zero (T12:1707).

BC Hydro stated that the technique it used was commonly accepted and used in other jurisdictions but only cites California as approving the technique (T12:1771).

Customers participating in the Power Smart Partners Program were only eligible for incentives if their payback was greater than 2 years. This rule was instituted in part to limit free ridership within the program (T12:1701). BC Hydro stated the methodology was useful in determining if a program participant may have undertaken EE measures at some time in the future without an incentive payment from BC Hydro (Exhibits B-75; B-87).

BC Hydro stated that it has undertaken a major industrial monitoring and evaluation study and planned on filing that report by the end of March 2007 (T12:1803).

6.1.2.8 Persistence of DSM Savings

Persistence refers to the length of time program-induced savings continue and thus is important in evaluating the effectiveness of a DSM program. BC Hydro distinguished between “measure persistence” which it defined as the number of years a system will remain operating and delivering baselines savings, and “claim persistence” which was described as: having incented the customer to implement an energy efficiency measure, when would the customer have implemented the measure in the absence of the program? (T12:1809). BC Hydro described the issue of persistence as a fundamental input into its analysis (T12:1810). BC Hydro also discussed the issue of “measure life” which is described as how long the measure will remain operating at high levels of efficiency before dying (T12:1811).

During testimony BC Hydro stated its intention to file a report regarding persistence (T11:1578-79) and that report subsequently became Exhibit B-64 which consists of five separate studies. The first study is a BC Hydro document entitled “QA STANDARD Technology: Effective Measure Life” dated September 11 2006. At page one of the report it states that the term “effective measure life” with respect to demand side management DSM savings refers to how long the savings are expected to last. The document then lists the effective measure lives used by Power Smart in calculating the persistence of savings (it does not define persistence). Three of the other studies appear to be the source documents for many of the estimates of effective measure lives used in the first document.

One of the filed studies notes that there is a distinction between “test measure life”, “operational measure life” and “effective measure life” (Exhibit B-64, “Persistence of Energy Savings: Review of Estimates of Measure Life”, p. 2). Effective measure life is then defined as considering not only field conditions, but also such factors as obsolescence, building remodeling, renovation, demolition and occupancy changes. The effective measure life is described as the estimate of the median number of years that the measures installed under a program are still in place and operable.

The Chair asked if BC Hydro was satisfied that the information to be filed on persistence was adequate support. BC Hydro replied, in part, that they had not conducted studies on persistence in the sense of going into buildings retrospectively and seeing whether the technologies installed under earlier DSM programs were still in place and operating properly. Instead they followed work elsewhere in the DSM field, and understood that their practice was in line with standard practice (T12:1810).

BC Hydro submits that "the savings that can result from DSM programs are assumed to last indefinitely because the new technology has been established on a permanent basis" (BC Hydro Reply, p. 76).

6.1.2.9 Market Transformation

BC Hydro stated that it Compact Fluorescent Light (CFL) Program "had achieved a high level of market transformation by creating the penetration of CFLs and saturation rates" (T12:1732). BC Hydro has claimed considerable energy savings as a result of this market transformation, and evaluated these amounts in two studies (Exhibit B-64).

These savings claims were supported in part by examining CFL usage in other jurisdictions. BC Hydro noted that the costs of producing CFLs have fallen "dramatically" (T11:1571), and agreed with Commission counsel that such dramatic price drops would normally be accompanied by a sharp increase in use (T12:1739).

BC Hydro stated that product quality of CFLs has improved mainly because of the requirements of California utility programs (T12:1739). BC Hydro agreed that the North American market for CFL was approximately 100 times bigger than the British Columbia market (T12:1737).

6.1.2.10 Conservation Potential Review

BC Hydro expected to complete a new CPR in 2007 and filed a scope document, which states that the objective of the CPR is to estimate potential energy and capacity savings over the next 20 years among BC Hydro's customer classes but which does not provide any indication that evaluation and monitoring of programs will form part of the review (Exhibit B-126). BC Hydro testified that the scope of the current CPR is not explicitly looking at changes in rates and consumption (T10:1486).

While most Intervenors voiced their support for cost effective DSM only two addressed the issues raised above. Intervenor submissions on load forecasting issues are considered in Section 3.1.

In addressing the load forecast with DSM savings, the JIESC states it recognizes that there are uncertainties with the timing and magnitude of EE2 savings but believes the projections with respect to the large industrial class are very reliable. While the JIESC is concerned with projections for the residential and commercial classes because they are normally verified by polling or sampling techniques, it believes the estimates are sufficiently accurate for the purposes of this proceeding (JIESC Argument, p. 10).

CEC recognizes that there is a potential that DSM evaluations might not account for some effect outside of the framework of the evaluation or may be flawed in other fashions. Nevertheless, it states that BC Hydro uses well-accepted and tested methods to monitor and measure results, and there is little doubt BC Hydro's Power Smart programs are having the effects intended (CEC Argument, pp. 28-29). In specifically addressing the issues of free rider, spillover and rebound effects, CEC submits there is little to no evidence before the Commission that the methodology is anything but appropriate (CEC Argument, p. 29).

Commission Determination

The Commission Panel notes at least two purposes for projecting savings attributable to DSM programs. The first is to adjust the load forecast, which forms the basis for determining necessary supply acquisitions. In this case, whether the savings are attributable to free riders or not is less important. All that matters is whether BC Hydro has correctly forecast total expected load. Double counting savings should be avoided. However, more rigour is required to link savings attributable to BC Hydro programs when evaluating the expected cost-effectiveness of those programs. Here free riders and claim persistence become important issues since they reduce the savings that are attributable to BC Hydro spending.

The Commission Panel recognizes that issues related to the monitoring and evaluation of DSM programs are complex. The Commission Panel further recognizes and commends the substantial efforts BC Hydro has made in designing and monitoring its programs.

However, the Commission Panel is concerned that, given the reliance placed on DSM by BC Hydro in closing the resource gap, and indications in the Throne Speech of greater reliance in the future, BC Hydro has not provided sufficient evidence that the forecast savings from proposed programs will in fact be achievable.

The primary source of the Commissions Panel’s concern is the lack of clearly defined and demonstrated linkages between naturally occurring conservation in: (1) the load forecast, (2) monitoring and evaluation, and (3) the CPR. This concern is first highlighted by the consideration given by BC Hydro to the impact of changes in the retail price of electricity based only on an assumption about its future rates. This concern is exacerbated by BC Hydro’s statement in Reply Argument that the savings from DSM programs are assumed to last indefinitely.

A good deal of evidence in the hearing was related to wholesale natural gas and electricity prices, yet BC Hydro’s own price to its customers was not modeled, but only assumed to be constant in real terms. The Commission Panel considers that future changes in BC Hydro’s overall rates, or rate structures, could have a significant impact on long-term electricity consumption, and are a component of natural conservation.

The Commission Panel has a similar concern that there is no explicit consideration of price change in the CPR, and is concerned that the path of natural conservation in the CPR could be mis-estimated in its absence.

BC Hydro notes that changes in the stocks of energy-using appliances are required for end-use models, but it is not clear how natural conservation and changes in saturation are incorporated in the load forecast.

The role of natural conservation and monitoring and evaluation are intertwined as was exemplified in the evidence on free riders and persistence. The Commission Panel is concerned that BC Hydro's methods only adjust for free riders for the short term. BC Hydro's evidence that its methodology was useful in determining if a program participant may have undertaken EE measures *at some period in the future* without an incentive payment was based on a survey that asked customers if they were going to undertake the upgrade *within two years* even in the absence of the incentive. If a customer would have undertaken an upgrade in the third year without an incentive the customer would not be a free rider in the first two years, but would be subsequently. This relates to the issue of persistence, and specifically "claim persistence", as defined in BC Hydro's testimony.

The Commission Panel is not convinced that BC Hydro has adjusted for this phenomenon. The information provided as part of Exhibit B-64 seems more properly characterized as effective measure life. In this context, the Commission Panel notes that there was no element of free ridership in the large industrial PSP program.

The Commission Panel considers the issue of market transformation to also be closely linked with the estimation of natural conservation.

The Commission Panel is concerned that BC Hydro has not studied the trajectory of its own retail rates in real terms. The Commission Panel notes the considerable efforts made in forecasting wholesale electricity prices and natural gas prices. The Commission Panel notes the evidence on negative margin which will increase the pressure on BC Hydro's rates, as will any significant investments in plant and equipment. **Therefore, the Commission Panel directs BC Hydro to file a report containing, among other things, a financial forecast of BC Hydro's rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. Input assumptions should be summarized in a concise, but comprehensive manner.**

The Commission Panel further directs BC Hydro to rely on the report for assumptions regarding retail prices in each of the CPR, the load forecast, and DSM evaluation methodologies. Furthermore, the report should identify and explain linkages, if any, of the impact of real retail prices in the CPR, the load forecast and BC Hydro's DSM evaluation methodologies between the assumption related to the retail price of BC Hydro electricity in the load forecast, CPR and evaluation methodologies to ensure. The report must demonstrate the consistent treatment in each, and address the concerns raised above. The Commission Panel believes such a report would be desirable at the time of the 2007 CPR, but notes that this was not an item in the terms of reference. In any event, the Commission will require such a report in advance of the implementation phase of the next round of EE programs.

6.2 Future Calls

6.2.1 2007 Call

BC Hydro submits that the 2007 Call is intended to:

- "meet BC Hydro's load/resource balance requirements;
- stimulate competition between all commercially proven technologies except nuclear power sources through an "all source" competitive call process. While it is anticipated that the 2007 Call will reflect the 2002 Energy Plan's 50 percent BC Clean Electricity target, the BC Clean Electricity target may be exercised as a constraint if a cost-effective non-BC Clean

Electricity project such as a 450 to 500 MW supercritical coal-fired generating facility were bid into the 2007 Call;

- broaden the range of proponents who can participate in the calls by accommodating larger projects and allowing for extended CODs and alternate call structures. The 2007 Call will target to procure approximately 5,000 GWh/yr of firm energy to, among other things, facilitate larger projects bidding into the 2007 Call to support economy of scale in projects. BC Hydro expects the 2007 Call to have staged and flexible CODs within an overall COD window of at least six years. During the Definition phase of the 2007 Call, BC Hydro will address issues related to how to effectively target the full range of allowed resource types over a broader range of in-service dates, while targeting energy delivery by F2015, and whether the F2006 Call's six month COD "grace period" should be extended;

- mitigate BC Hydro's exposure to rising prices and volatility in the wholesale spot market; and

- replace Burrard firm energy (6,100 GWh/yr) to the extent it is cost-effective to do so".

(BC Hydro Argument, pp. 88-89).

After the Throne Speech BC Hydro, in its Reply, addresses the impact on its original plans for the 2007 Call that the Throne Speech has, or may have had:

> "The need for an open, "all-source" call for resources sufficiently large to attract large projects has not diminished with the Throne Speech. While the Throne Speech signals a change to the voluntary 50% BC Clean Energy target established in the 2002 Energy Plan, no new resource options have been banned. To ensure the most cost-effective call process, detailed call design analysis is essential to assess the risks presented by the proposed Throne Speech GHG requirements and how those risks are best addressed. It will also be necessary to consider the Throne Speech pronouncement that at least 90 percent of electricity is to come from "clean, renewable" sources. BC Hydro will be engaging IPPBC, individual IPPs, customer intervenors and other stakeholders in the design of the 2007 Call. The potential for increased F2006 Call attrition due to the Throne Speech requirement that coal-fired generation projects must sequester GHG emissions and the potential for a narrower range of resource options are issues that will need to be addressed as part of the proposed 2007 Call NSP and the next LTAP" (BC Hydro Reply, p. 12).

BC Hydro sets out the timeline for the 2007 Call as follows:

- **Stakeholder Engagement**: BC Hydro states that it has commenced dialogue and consultation with IPPs (T20: 3027), and proposes discussions with its customer groups, and other stakeholders, regarding the design and preliminary terms associated with the 2007 Call, after receipt of the expressions of interest (T20:3054);

- **Expressions of Interest:** BC Hydro states that after receipt of a positive BCUC decision concerning the 2007 Call, it proposes to issue a Request for Expressions of Interest in the spring of 2007 (T20:3054);

- **Negotiated Settlement:** BC Hydro states that it proposes to circulate a draft detailed term sheet setting out the key risk allocation issues and other terms and conditions, leading to a Commission-sponsored NSP in the fall of 2007, but that it does not propose to circulate *pro forma* EPAs in advance of the NSP. BC Hydro submits that the key terms and conditions should be vetted prior to spending time drafting detailed *pro forma* EPA details;

- **Commission Input:** BC Hydro submits that the IPPs are concerned that they learn as early in the process as possible whether there is a significant regulatory concern with respect to any EPAs they are entering into with BC Hydro and that, if each individual EPA faces the prospect of regulatory review, significant transaction costs are added. Accordingly, whether or not the NSP results in a negotiated settlement, the Commission would be afforded an opportunity to provide comment on the term sheet;

- **Issuance of the 2007 Call:** BC Hydro states that the target period for the issuance of the 2007 Call would be late 2007;and

- **Section 71 Filing:** BC Hydro states that it will file EPAs with the Commission as "energy supply contracts" pursuant to section 71 of the *UCA* with a full, reasoned report on the evaluation process and outcome.

  (BC Hydro Argument, pp. 90-91)

In order to assist with the stakeholder engagement and NSP processes, BC Hydro seeks the Commission's comment on the following proposed aspects of the 2007 Call design:

- Targeted acquisition volume of 5,000 GW.h/yr of firm energy;

- Flexible and staged commercial operation dates (COD) within an overall COD window of at least six years;

- Adoption of the F2006 Call allocation of GHG liability; and

- The allocation of gas and electricity price risk between BC Hydro and IPPs.

BC Hydro submits that it is not seeking the Commission's comment on the Call structure (i.e., whether to use a Request for Proposal process, or a Call for Tender process, or a hybrid of the two) or the desirability of permitting projects located outside of B.C. to bid into the 2007 Call (BC Hydro Argument, p. 10).

IPPBC states that its filed evidence and cross-examination were designed to raise a number of concerns about the "Large Project EPA" that was used in the F2006 Call as they may relate to the proposed 2007 Call, including:

- pricing complexity;
- more flexible commencement and Commercial Operation Dates;
- limited flow-through of uncontrollable costs;
- bid qualification and performance deposits; and
- system losses and network upgrade costs,

and that its two primary purposes in raising these matters are to:

- place on the record contractual and evaluation issues and material relating to these issues so that the Commission and, other intervenors have a more comprehensive understanding of them, since without access to this material, they can be very difficult to understand. and since the contract and evaluation criteria determine the product, including price, that IPPs provide to BC Hydro; and
- provide one objective means of comparing the product, including price, which IPPs deliver against Power Smart, Resource Smart and Load Displacement alternatives.

IPPBC states that it is not requesting the Commission to make any orders or directions with respect to the evaluation criteria or contractual terms that may be used for the 2007 Call, with the following exceptions:

- That if the Commission decides that natural gas generation should be included in the 2007 Call, that BC Hydro and not IPPs take natural gas price risk and that any calls for new supplies of electricity be structured accordingly; and
- EPAs be reasonably acceptable to lenders in the financial markets where IPPs borrow money to finance their projects (IPPBC Argument, pp. 21-22).

IPPBC states that it supports BC Hydro's proposal for a negotiated settlement process, in that it will provide a more suitable forum for the discussion of evaluation criteria and contract terms and conditions with any outstanding issues to be settled by the Commission through an oral hearing process and requests:

- that the Commission confirm by order or direction, BC Hydro's proposal for a 2007 Call negotiated settlement process which it would conduct; and
- that the Commission order or direct BC Hydro to make available the full pro forma 2007 Call contract and evaluation criteria prior to the commencement of this negotiated settlement process.

  (IPPBC Argument, p. 23)

Mr. Campbell, a director of IPPBC testified that he would prefer that the Commission opine on a *pro-forma* EPA than a Term Sheet but that he realized that the *pro-forma* EPA would add time to the regulatory approval process and that time to a project developer is critical …

> "So, all other things being equal, we prefer the contract approved rather than a term sheet, but all other things are not equal… it's going to be a …longer approvals process, and if that's the case, where is the dividing line? If it -- personally, this is just Pristine [his company], if it was going to take an extra month because we're going with a contract rather than a term sheet, I'd say "Go with the term sheet" (T23:3721).

CPC submits that its Waneta Expansion Project shares most attributes of both the Resource Smart and the IPP buckets, and encourages BC Hydro to develop the structure, terms and conditions of the 2007 Call or alternative acquisition processes in a manner that appropriately accommodates and values the unique attributes and benefits of Resource Smart-like non-BC Hydro supply options (CPC Argument, p. 4).

CPC submits that allowing for alternate call structures and alternative acquisition processes, staged and flexible CODs and appropriate extensions of the six-month COD “grace period” is important to enable bids from larger projects. Further, CPC submits that exploring appropriate terms and conditions for acquiring power from existing projects and the combined output of two or more projects in BC is also important to enable a full range of cost-effective resource options (CPC Argument, p. 5).

CPC submits that the $3/MW.h credit for hourly versus monthly firm energy may have been intended as a proxy for the value of capacity, but it did not achieve its objective. Capacity gives the ability to deliver electricity on a firm basis when it is most needed and most valuable, and by not recognizing the value of capacity as it relates to the timing of firm energy deliveries, the $3/MW.h credit significantly undervalued capacity, particularly for low capacity factor projects, and may have had the unintentional effect of precluding bids for hourly firm energy from projects with the capacity to do so (CPC Argument, p. 6).

CPC submits that the pricing provisions in the F2006 Call discounted the monthly price adjustment factors of firm energy bid in the freshet period by establishing artificial price tiers, which deemed firm energy to be non-firm and HLH (peak) energy to be LLH (off-peak), for bid price offer and bid evaluation purposes. This artificial price tiering can unduly discriminate against run-of-river and freshet-rich hydro power projects, forcing them to bid a much higher price to compensate for the effect of the artificial price tiering. The resulting higher bid price could render otherwise economic hydro project bids uneconomic. CPC submits that its evidence in this regard was uncontested in cross-examination, namely, that all like energy supplied during any given time period has the same marginal value, regardless of its source, and should receive the same price (CPC Argument, p. 7).

The JIESC submits that non-determinative non-binding "comments" are not helpful and should be avoided. The Commission should leave these issues to be determined in the appropriate proceeding (for example, the 2007 Call NSP or the approval proceedings surrounding EE3, EE4 and EE5) rather than addressing the issues with non-binding, non-presumptive comments. These non-binding comments often become fodder for one side or the other, locking them prematurely into a position in a debate that is still theoretically open and should remain open (JIESC Argument, p. 7).

BCOAPO generally supports BC Hydro's requests in respect of the 2007 Call, but counsels: "Regarding the larger-scale planning issues, including the proposed future Calls and the ultimate fate of Burrard, we submit that it would be imprudent of the Commission to make premature decisions that lock us into trajectories that are vulnerable to government policy changes in the coming period. That is, one of the most useful responses in a time of uncertainty and change is to keep our options open" (BCOAPO Argument, para. 18).

BCOAPO submits that gas price risk should be assumed by BC Hydro, while the financial and regulatory risk for developers of GHG-emitting resources should reside with the developer (BCOAPO Argument, paras. 93, 97). BC Hydro should be required to put forward a study that estimates its own cost of developing any new large gas fired plant as part of the Section 71 filing of any contract with an IPP to develop a large gas fired facility. The Commission will then be in a position to set revenues requirements based on the lesser of BC Hydro's own cost estimate or the IPP cost (BCOAPO Argument, para. 96).

BCOAPO submits that BC Hydro has failed to explore the potential benefit that might arise through the use of what it terms swaps with respect to extra-provincial resources and transactions, and suggests that BC Hydro identify the regions in which Powerex trades, and where Powerex could use physically-backed resources to enhance its trading activity, and solicit resource bids in these regions and, assuming they are competitive with other bids received in the 2007 Call, should determine if there are opportunities to develop beneficial energy swap arrangements (BCOAPO Argument, para. 98-99).

SCCBC submits that the Commission Panel comments which BC Hydro requested it make on the proposed 2007 Call should take into account its evidence and submissions concerning:

- the $3/MW.h "firming" premium used in the F2006 Call to evaluate tenders that chose to deliver hourly firm rather than the baseline monthly firm energy resource;
- the nature of the shortfall liquidated damages clause in the F2006 Call EPAs; and
- the operational costs of wind integration as examined on other systems and for consideration in British Columbia

and state that their evidence regarding the firming premium and liquidated damages clause in the F2006 Call is directed toward potential lessons to be learned for future calls, and not to revisit the F2006 Call (SCCBC Argument, pp. 14-15).

BC Hydro submits that it no longer seeks Commission comment in relation to any proposed aspect of the 2007 Call design agreeing with instead the JIESC that in today's circumstances all features of the 2007 Call are best addressed through stakeholder engagement and (through) the proposed NSP, where the complex details be properly weighed and considered to design the most competitive and cost-effective call possible. BC Hydro submits that the Commission will be afforded an opportunity to provide comment on the 2007 Call term sheet and mandatory criteria whether or not the NSP results in an agreement or not (BC Hydro Reply, p. 17).

BC Hydro also submits that the Commission has no jurisdiction to compel it to make available the full *pro-forma* 2007 Call contract prior to the commencement of the NSP (BC Hydro Reply, pp. 31-34).

Commission Determination

The Commission Panel was originally requested by BC Hydro to "comment" on certain aspects of the 2007 Call, and by certain Intervenors to make other comments or give BC Hydro directions in respect of certain aspects of the 2007 Call. While most Intervenors were in favour of BC Hydro's requested comments, the JIESC submitted that non-determinative and non-binding comments were not helpful and should be avoided. The Commission Panel agrees with this submission and will not make such comments.

So far as concern the aspects of the 2007 Call raised by the various parties in argument the Commission Panel finds that BC Hydro has both the responsibility and the obligation to manage the Call which includes, but is not limited to the following actions:

- establishing the volumes and the nature of the product to be the subject of the Call;
- establishing the structure of the Call;
- setting the terms and conditions;
- determining a suitable allocation of various risks to the parties most capable of managing them, having regard to cost-effectiveness and the “bankability” of the EPAs; and
- establishing the evaluation criteria,

and that as part of its responsibility and obligation, BC Hydro should be required to communicate in a transparent manner to its IPP suppliers and other stakeholders its reasons for establishing the various terms and conditions; risk allocation concepts; and evaluation criteria in the Call.

The Commission Panel notes that BC Hydro is not requesting approval of a Call volume at this time and the Commission Panel will not comment on the proposed volume of the 2007 Call at this time. The onus is on BC Hydro to justify the target call volume and the volume of any subsequent awards. The Commission Panel notes considerable uncertainty regarding the appropriate volume in the absence of a formal application regarding Burrard and a clearer economic justification for the further substitution of market resources with long-term purchases of additional domestic non-firm resources in BC Hydro’s non-firm / market allowance.

The Commission Panel finds that the evidence presented to it during the hearing on the issue of BCOAPO's swaps was not adequate for it to determine whether such opportunities exist, and suggests that BCOAPO make its case to BC Hydro during the stakeholder engagement process as part of the 2007 Call.

So far as concerns the submissions of SCCBC concerning the $3/MW.h timing premium and the LDs for under-delivery; CPC concerning the $3/MW.h timing premium and the valuation of freshet energy; and IPPBC concerning the allocation of natural gas price risk and the bankability of future EPAs, the Commission Panel will not make any specific determination, other than to expect BC Hydro to address these and other concerns of its stakeholders during the negotiation process.

The Commission Panel accepts BC Hydro's proposed timeline for the 2007 Call and directs it to file with the Commission the necessary application for an NSP.

So far as concerns BC Hydro's stated intention not to circulate *pro-forma* EPAs in advance of the NSP, but to use a summary of key terms and conditions (generally referred to as a Term Sheet) for the purposes of the NSP, the Commission Panel notes that IPPBC made its submission that BC Hydro should be required to make available the full *pro-forma* 207 Call EPA prior to the commencement of the NSP despite the fact that one of its witnesses testified that he would prefer to negotiate from a Term Sheet as to negotiate from a full *pro-forma* EPA would be time consuming and that BC Hydro submitted in its Reply that the Commission lacks the jurisdiction to compel it to produce *pro-forma* EPAs as part of a review of a Section 45(6.1) plan.

The Commission Panel is mindful that time is of the essence for IPP developers and that the period between the NSA and the issue of the Call is high risk time for them and accordingly will not compel BC Hydro to make the full *pro-forma* EPA available prior to the commencement of the NSP.

So far as concerns the matter of jurisdiction the Commission Panel distinguishes the 2007 Call from the F2006 Call in one important feature, notably that as of August 2005, a *pro-forma* EPA for the F2006 Call did not exist. Had the IPPBC witness panel and other Intervenors been unanimous in their desire to see pro-forma EPAs prior to the commencement of the NSP, the Commission Panel may well have determined that it has the jurisdiction to make such an order.

So far as concerns an attrition allowance for the 2007 Call, the Commission Panel determines that the allowance should be Call-specific and directs BC Hydro, when evaluating the results of the 2007 Call, to use its best estimate of the likely attrition factor by taking into account all relevant factors, including:

- the steps it has taken in the conduct of the Call to minimize attrition;
- the technology and location of the projects;
- the experience of the developers and their sponsors; and
- any relevant terms and conditions of the EPAs themselves.

BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $2,875,000 required to undertake and complete the identification phase work for the 2007 Call are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07.

6.2.2 2009 Call

BC Hydro submits that the LTAP identifies two "all source" competitive call processes to acquire energy from other persons and that expenditures of $520,000 required to undertake and complete the identification phase work for the 2009 Call are in the interest of persons within B.C. who receive or may receive service from BC Hydro (BC Hydro Argument, pp. 79, 93).

Only BCOAPO submits that it does not agree with BC Hydro's submission in this regard in that it is premature in view of the host of unresolved issues, which must be determined before the nature and scope of such a call can be analyzed (BCOAPO Argument, p. 4). The remaining Intervenors support these expenditures.

Commission Determination

BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $520,000 required to undertake and complete the identification phase work for the 2009 Call are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07. The Commission Panel notes that BC Hydro is not requesting approval of a Call volume at this time and the Commission Panel will not comment on the proposed volume of the 2009 Call at this time.

6.3 Resource Smart

Resource Smart projects in the implementation phase, or in the definition phase with a strong likelihood of proceeding, are identified in the Resource Smart category under Existing and Committed Supply in Tables 8-2 and 8-3 of Exhibit B-55. These projects are the Aberfeldie Redevelopment Project, which has received a CPCN by Order No. C-2-07 and the G.M. Shrum Generating Station Capacity Increase Units 6, 7 and 8.

BC Hydro has requested Orders regarding two other Resource Smart projects in the 2006 IEP/LTAP filing, those projects being Revelstoke Unit 5 and the next capacity increase at either Revelstoke or Mica. The resource additions associated with these two projects are shown under Proposed New Supply in Tables 8-2 and 8-3 of Exhibit B-55.

CPC observes that BC Hydro has acknowledged that the Waneta Expansion Project has attributes similar to Resource Smart projects (CPC Argument, p. 3).

6.3.1 Revelstoke Unit 5

The Revelstoke Unit 5 project is the installation of the fifth generating unit at the Revelstoke Generating Station, which was originally constructed with four operating units but with space for up to six units. The benefits associated with Revelstoke Unit 5 include 480 MW of dependable capacity, an associated 120 GW.h/yr of firm energy, and system benefits such as energy shaping. BC Hydro is targeting an in-service date of F2011 (Exhibit B-1A, p. 8-28).

BC Hydro contends that, in addition to the evidence in this Hearing that shows that Revelstoke Unit 5 is required on or before its earliest possible in-service date, two material events have occurred since the load/resource balance presented in Exhibit B-55 was prepared, both of which accelerate the need for the dependable capacity associated with Revelstoke Unit 5. The first event was that BC Hydro has completed a new peak load forecast that indicates the peak demand has increased between 120 MW to a little over 200 MW in the 2010 to 2015 period. The second event was the rejection of the LTEPA+ by the Commission in Order No. G-176-06 (BC Hydro Argument, p. 100). This pressure to accelerate the development of Revelstoke Unit 5 has been compounded by the potential for increased F2006 Call attrition and a potentially narrower range of resource options as a result of the stringent GHG sequestration and offset requirements proposed in the Throne Speech (BC Hydro Reply, pp. 13-14).

BC Hydro claims that Revelstoke Unit 5 aligns with the Throne Speech in that it is a BC Clean Electricity project, does not emit GHGs, makes more efficient use of water and with the net increase in generation, will assist BC Hydro in meeting the Provincial requirement that B.C. be electricity self-sufficient by 2016 (BC Hydro Reply, p. 13).

BC Hydro states that there are no B.C.-based capacity alternatives to Revelstoke Unit 5 that are available as early as F2011. However, BC Hydro acknowledges that the Waneta Expansion Project has physical attributes that may be similar to Resource Smart projects, but claims that since neither a bid nor a firm offer for supply from the Waneta Expansion Project has been received, the project cannot be relied upon or fully evaluated (BC Hydro Argument, pp. 100-101).

BC Hydro also states that assigning the use of the CE as an alternative to Revelstoke Unit 5 would be a more costly option, would reduce the flexibility of the CE as a contingency resource or as tool in Powerex's marketing and trading operations, and would further increase BC Hydro's reliance on external capacity beyond the 400 MW of capacity reserves already being relied upon from neighbouring control areas (BC Hydro Argument, p. 101).

BC Hydro provided references to studies conducted by BCTC at BC Hydro's request that showed the delivery of Revelstoke Unit 5 supply to the Lower Mainland is not dependent on, and does not require, the ILM transmission system reinforcement (Exhibit B-131).

Finally, BC Hydro requests a determination under Section 45(6.2)(b) of the Act that expenditures of $12.5 million in F2007 and F2008 required to complete the Definition phase of Revelstoke Unit 5 are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 13).

BCOAPO strongly supports Revelstoke Unit 5 because the additional dispatchable capacity will allow the utility to reduce energy purchases during high price periods, and take advantage of volatility to increase trade revenue (BCOAPO Argument, para. 66, 101).

CEC supports BC Hydro moving ahead quickly with Revelstoke Unit 5 and filing a CPCN application (CEC Argument, p. 54).

IPPBC is in favour of Revelstoke Unit 5, subject to reviewing the material BC Hydro files as part of the CPCN application for this project (IPPBC Argument, p. 32).

The JIESC would like to see Revelstoke Unit 5 advanced even faster than currently proposed by BC Hydro (JIESC Argument, p. 2). Although the JIESC believes that BC Hydro has undervalued Revelstoke Unit 5 by failing to account for the full trade benefits that would be associated with Revelstoke Unit 5, and that determining the value of these benefits was difficult, the JIESC strongly support this project (JIESC Argument, p. 20).

Terasen supports BC Hydro's requested determination regarding Revelstoke Unit 5, namely approval of $12.5 million to complete the Definition Phase work (Terasen Argument, p. 2).

Vanport requests that any approval of funding to complete the final cost studies for Revelstoke Unit 5 should be conditional on also providing funding for a pre-feasibility study of Vanport's proposed pumped storage hydro plants (Vanport Argument, p. 5).

Commission Determination

The Commission Panel concludes that BC Hydro's options for acquiring adequate capacity in the near-term are limited and that, based on BC Hydro's preliminary analysis, Revelstoke Unit 5 may be a cost-effective capacity addition. BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $12.5 million in F2007 and F2008 required to complete the Definition phase of Revelstoke Unit 5 are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro was approved in Order No. G-29-07.

The Commission Panel directs BC Hydro to include the Waneta Expansion Project in its next ROR. The Commission Panel directs BC Hydro to include a pumped storage hydro project on the Jordan River in its next ROR. The Commission Panel notes that the onus remains with BC Hydro to demonstrate the cost-effectiveness of Resource Smart projects relative to other potential sources of new capacity in any CPCN application, and that the CPCN proceedings remain the best venue for Intervenors to provide evidence and argument regarding alternate sources of capacity.

6.3.1 Revelstoke Unit 6 and Mica Unit 5

The Revelstoke Unit 6 project and the Mica Unit 5 project are the next two capacity units of the Heritage Resources that could be brought into service after Revelstoke Unit 5. The Mica Unit 5 project is similar to the Revelstoke Unit 5 project as it consists of the installation of the fifth generating unit at the Mica Generating Station, which was originally constructed with four operating units but with space for up to six units. The Revelstoke Unit 6 project would complete the installation of the final unit at the Revelstoke Generating Station.

BC Hydro claims that either Revelstoke Unit 6 or Mica Unit 5 is required for system reliability purposes as early as F2013. Development risks for Revelstoke Unit 6 or Mica Unit 5 are expected to be similar to Revelstoke Unit 5, putting them at the relatively low end of the development risk scale (BC Hydro Argument, p. 104).

BC Hydro argues that for the same reasons set out with respect to the need for Revelstoke Unit 5, advancement of either Revelstoke Unit 6 or Mica Unit 5 is urgent. The Investigation and Definition phase work related to Revelstoke Unit 6 or Mica Unit 5 is critical to ensure that the most appropriate capacity project is selected to be developed next, and that upcoming Resource Smart capacity projects are maintained at the appropriate development stage to help meet reliability requirements, augment IPP supply contributions and maintain operational flexibility in a GHG-free manner. In support of this objective, BC Hydro requests a determination under Section 45(6.2)(b) of the UCA that expenditures of $1.0 million in F2007 and $2.0 million in F2008 required to complete the Identification and Definition phase work for the next Revelstoke or Mica Unit are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro (BC Hydro Reply, p. 14)

Each project is expected to take five to six years to complete once a decision has been made to start the Definition phase of development (BC Hydro Argument, p. 105).

BCOAPO submits that BC Hydro should further investigate Revelstoke Unit 6 and Mica Unit 5, and observes that these initiatives made sense prior to the Throne Speech, and make even more sense now (BCOAPO Argument, p. 18).

CEC encourages BC Hydro to proceed with a full evaluation of the other three potential projects of Mica and Revelstoke, particularly to examine the potential merits of advance development of these resources (CEC Argument, p. 55).

Terasen supports BC Hydro's requested determination regarding Revelstoke Unit 6 and Mica Unit 5, namely approval of a combined $3 million in F2007 and F2008 to complete the Identification and Definition Phase work for the next project (Terasen Argument, p. 2).

Commission Determination

Given the evidence regarding the growing need for capacity and the relatively small expenditures required to keep the Revelstoke Unit 6 and Mica Unit 5 options open, the Commission Panel agrees that BC Hydro should proceed with the Identification and Definition phase work for the two projects. **BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $1.0 million in F2007 and $2.0 million in F2008 required to complete the Identification and Definition phase work for the next Revelstoke or Mica Unit are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro was approved in Order No. G-29-07.**

6.4 Interior to Lower Mainland Transmission Reinforcement Project

The currently proposed ILM is a 251 kilometre 500 kV single circuit steel tower transmission line, designated 5L83, between the Nicola substation near Merritt and the Meridian substation in Coquitlam. An alternative also under review is a 203 kilometre 500 kV single circuit steel tower transmission line, designated 5L46, between the Kelly Lake Substation near Clinton and Cheekeye substation near Squamish (Exhibit B-1B, Appendix F, Appendix B, pp. 122-123; T22:3495-96). The capital cost projection by BCTC in this proceeding for the ILM is approximately $320 million in 2006 dollars and $350 million in inflated dollars (Exhibit C7-8, BCUC 1.2.1, Table 2).

BC Hydro submits that the evidence demonstrates that the ILM is required at some time, and the only portfolio in the 2006 IEP that did not require the ILM was dependent upon an additional 1,700 MW of dispatchable, probably gas-fired, generation and an additional 1,000 MW of load reduction from EE3, EE4 and EE5, both in the Lower Mainland and Vancouver Island regions (BC Hydro Argument, p. 111).

BC Hydro undertook an analysis to identify the relationship between the repowering of Burrard and the timing of the ILM (Exhibit B-146A). BC Hydro claims the analysis shows that even if the repowering of Burrard was to proceed, the ILM is still required at its earliest in-service date, which BCTC identifies as F2015 (Exhibit B-146A, Appendix D, p. 2), unless BC Hydro were to rely upon CE for firm capacity during the Burrard repowering cycle. In such a scenario, BC Hydro's reliance on the external market would range between 600 MW and 1,300 MW depending on the timing of resource additions. At the higher end, this would exceed the physical size of the CE (BC Hydro Argument, p. 112).

BC Hydro submits that even if the evidence of Exhibit B-146A was found to support an option of pursuing the repowering of Burrard, the ILM should not be deferred based on an assumption that the Burrard repowering will be completed on time. BC Hydro claims there would be no realistic back-up plan to reliably serve the electricity demand in the Lower Mainland/Vancouver Island region through the Burrard repowering activities. On the other hand, BC Hydro states that if the ILM proceeds, but experiences some unforeseen delay, BC Hydro would continue to make every effort to keep Burrard available to provide all of its services until the ILM is ultimately completed (BC Hydro Argument, p. 113).

BC Hydro claims that loss reductions attributable to the ILM would be substantial. BC Hydro interprets the data supplied by BCTC (Exhibit C7-8, BCUC 1.2.1) as showing the loss savings would offset 75 percent to 80 percent of the early year capital costs if valued at $74/MW.h and 55 percent to 60 percent if valued at the BC Hydro 2006 Electricity Market Price Forecast (BC Hydro Argument, p. 113). BCTC has concluded the ILM should provide incremental flexibility and opportunity for increasing trade benefits, but has not performed any study to quantify these potential opportunities and benefits (Exhibit C7-8, BCUC 1.13.1).

BCTC observes that the timing of the ILM is a function of the choices made with respect to generation options included in the LTAP, CRPs and the decision to pursue repowering of Burrard, but claims that the ILM will be required at some time irrespective of a decision to pursue Burrard repowering, and failure to proceed with development work for ILM reinforcement is risky, given the contingencies. BCTC urges the Commission not to use the benefits associated with a deferral of the ILM as a consideration of whether or not to pursue the repowering of Burrard (BCTC Argument, para. 11).

BCTC's interpretation of the analysis contained in Exhibit B-146A is that Burrard repowering could defer the ILM by between zero and six years if using NITS planning assumptions and by between zero and five years if using IEP/LTAP assumptions. The deferral period was dependent on the addition of resource options and resource dispatch assumptions (BCTC Argument, para. 14).

BCTC claims the ILM offers significant operational and reliability benefits including increased generation dispatch flexibility, increased transmission maintenance flexibility, improved system stability, power quality benefits, and a stronger system for N-2 contingencies (BCTC Argument, para. 18).

BCOAPO supports the ILM in principle, and submits that it should progress to its next stage of development (BCOAPO Argument, para. 109).

CEC agrees with BC Hydro that the strengthening of the ILM corridor should be both a priority and undertaken as proposed (CEC Argument, p. 60).

IPPBC observes that the ILM could result in potential trading benefits, and notes that it is unclear whether or not studies had been undertaken to identify these trading benefits (IPPBC Argument, pp. 32-33).

The JIESC strongly supports moving the ILM forward for regulatory and environmental approval. The JIESC accepts that the ILM reinforcement is overdue and that its value is not contingent upon any particular development (JIESC Argument, p. 16).

The JIESC also expects that when a detailed review of ILM is carried out it will show substantial trade benefits, particularly in the early years (JIESC Argument, p. 16).

Commission Determination

The Commission Panel notes that BC Hydro and BCTC appear to differ in their interpretation of Exhibit B-146A. Nevertheless, the Commission Panel accepts the evidence in Exhibit B-146A that the ILM reinforcement is required sometime in the 7 to 15 year timeframe regardless of decisions on the repowering of Burrard. Therefore, in light of the loss savings, potential trade benefits, and possibility for implementation delays associated with the ILM, the Commission Panel expects that BCTC will be proceeding with its current schedule to bring forward a CPCN application for the ILM. The Commission Panel expects the ILM CPCN Application will contain a comprehensive comparison of route options and a comprehensive evaluation of trade benefits.

7.0 CONTINGENCY RESOURCE PLANS

The requirement for Contingency Resources Plans ("CRPs") to supplement the LTAP Base Case arise from Attachment J of the BCTC Open Access Transmission Tariff ("OATT"), which states that a NITS application can incorporate high and low load forecast scenarios and resource plan contingencies as approved by the Commission. A NITS application that contains such approved CRPs shall be considered one service request, and transmission capacity will be reserved to the extent it is available to serve the entire request, in accordance with the queue priority of the NITS application. If there is insufficient Available Transmission Capacity ("ATC") to meet the service request, transmission studies will be conducted to identify transmission system upgrades for each load forecast scenario and for each resource plan contingency separately (Exhibit C7-7, Appendix 1).

In addition to the LTAP Base Case, BC Hydro has prepared and submitted two CRPs in this Application. The Base Case contemplates a specific portfolio of resource additions in response to the proposed 2007 and 2009 Calls based on new resources selected on a least cost basis from the 2005 ROR. The response to the Calls could result in resources that differ from this anticipated response. The CRPs have been developed to allow for this divergence from the expected response, and therefore, BC Hydro claims the CRPs should be sufficiently flexible and diverse from one another to reflect a range of different outcomes (Exhibit B-1E, pp. 8-54 to 8-55).

BC Hydro claims that it has identified reasonable long-term planning risks and uncertainties, including those affecting transmission planning, and that the two CRPs properly address those risks and uncertainties (BC Hydro Argument, p. 115). Specifically, BC Hydro states the CRPs expressly consider load forecast uncertainty, DSM deliverability, and supply side (IPP) type and location uncertainty (BC Hydro Argument, p. 116).

The LTAP Base Case provided by BC Hydro was based on the Mid Load Forecast, expected DSM response, and as described above, summarized the planning level identification of the resources associated with the 2007 and 2009 Calls. The 2007 Call is shown to be composed of a diverse group of sources including geothermal, small and medium hydro and wind, with the majority located in the Lower Mainland region, with the exception of a wind bundle in the Peace Region, accounting for less than 30 percent of the 2007 Call energy. The 2009 Call identifies two large pulverized coal supercritical facilities, one in the Peace Region and the other in the East Kootenay Region, both coming on-line in F2019 or later (Exhibit B-55, Appendix O, Table 7).

Contingency Resource Plan 1 ("CRP1") has been designed to compensate for the high load forecast and less than expected dependable capacity contribution from resource additions, and with the expected DSM response. The resources associated with the 2007 Call response for CRP1 are similar to those used in the LTAP Base Case, but the 2009 Call response is composed of a group of resources with significant diversity in both location and fuel type, with emphasis on a gas turbine type resource in the Kelly Lake/Nicola Region (Exhibit B-55, Appendix O, Table 8).

Contingency Resource Plan 2 ("CRP2") has also been designed for the high load forecast and less than expected dependable capacity contribution from resource additions, but with the DSM response 20 percent less than expected. The resources associated with the 2007 Call response for CRP2 provide only 50 percent of the anticipated new resources from the Lower Mainland/Vancouver Island region compared to the LTAP Base Case and CRP1. The 2009 Call response for CRP2 is similar to that used in CRP1 (Exhibit B-55, Appendix O, Table 9).

BC Hydro requests Commission approval of the LTAP Base Case and the two CRPs set out in Exhibit B-1E and Exhibit B-55 for submission in BC Hydro's 2006 NITS update/application and asks the Commission to confirm the proposed CRPs are directionally appropriate (BC Hydro Argument, pp. 115-116). BC Hydro believes the flexibility of a "directionally appropriate" confirmation is consistent with the OATT and that replacement in the NITS Agreement of contingency resources (type or volume) located within a major transmission region, and in an approved CRP, with contingency resources located within the same transmission region should not require further regulatory approval. BC Hydro points out that new supply resources come from the private sector, which creates uncertainty in resource options, and the CRPs must include considerable flexibility to manage this uncertainty (BC Hydro Reply, p. 69).

Upon receiving a NITS application, which may contain CRPs approved by the Commission, BCTC proceeds to process and analyze the application in accordance with the OATT. The transmission system upgrades that are required to satisfy the service request in the NITS application are then included in subsequent BCTC Transmission System Capital Plans ("TSCPs") or in CPCN applications. BCTC proposes that, while the Commission has the ability to review and approve transmission system upgrades through either the TSCP or CPCN application processes, it is in the LTAP review and BC Hydro CPCN applications where the need for generation resources that drive the overall need for the new transmission facilities is to be reviewed and these decisions are not revisited in BCTC's TSCP or CPCN proceedings (BCTC Argument, para. 9-10).

BCTC submits that the Commission should consider the transmission implications of BC Hydro's CRPs and although BCTC does require a definitive answer regarding whether or not the CRPs are approved for the purposes of the NITS application, it does not take a position on whether or not the CRPs are appropriate (BCTC Argument, para. 23). BCTC describes that Attachment J of the OATT requires BCTC to place in the queue a reservation for transmission capacity for Commission-approved CRPs at the time a NITS application is made, but not at the time the CRPs are approved. BCTC may then release the reserved capacity to others on a 60-day rolling-window basis only to the extent that it is not required to accommodate a service request contemplated in the NITS application that first caused the transmission capacity to be reserved. If the reserved capacity is required to accommodate a service request contemplated in the NITS application, then generation that was identified in either the LTAP Base Case or approved CRPs must be designated at least 60 days in advance of the time that the service request is required to come into effect. As long as a NITS transmission reservation does not have a generation-backed service request nominated against it, the reserved transmission capacity is released for the next 60 days (BCTC Argument, para. 27).

BCTC points out that if any new facilities are identified to satisfy the NITS application, including accommodation of approved CRPs, a Facilities Agreement must be executed within 60 days of BCTC presenting such an agreement following the processing of the NITS application. The Facilities Agreement requires the NITS applicant to pay for the identified new facilities. BCTC submits that it is important to maintain the link between payment of facilities costs and reservation of transmission capacity for resource contingencies (BCTC Argument, para. 31).

As discussed in Section 4.4.6 of this Decision, Exhibit B-102 described some differences in the transmission planning assumptions as they are applied against the IEP, LTAP and NITS analyses, and proposed that, based on studies to be performed by BCTC, some of the planning assumptions may change before BC Hydro submits its next NITS application. Subsequent to Exhibit B-102, in a report titled "Impact of Burrard Re-Powering on ILM Reinforcement Timing, BCTC claimed significant differences between the NITS planning assumptions and the 2006 IEP/LTAP planning assumptions used for that report (Exhibit B-146A, Appendix D). These planning assumptions are shown in the table below.

ITEM	NITS Planning Assumptions	2006 IEP/LTAP Planning Assumptions
1	Each BC Hydro plant and each dispatchable IPP generating plant (including plants of FortisBC and Teck Cominco Metals Ltd. ("TCML")), in the South Interior ("SI") and North Interior ("NI") is assumed to be operating at its MCR.	Each BC Hydro plant and each dispatchable IPP generating plant (including FortisBC and TCML plants) in the Interior (SI and NI) is assumed to be operating at its DGC rating.
2	Each intermittent resource in the Interior is assumed to be operating at its MCR.	Each intermittent resource in the Interior is assumed to be operating at its ELCC level.
3	Each BC Hydro and IPP generating plant in the Coastal region is assumed to be operating at its DGC.	Each BC Hydro and IPP generating plant in the Coastal region is assumed to be operating at its DGC.
4	The ILM flow is determined by dispatching the aggregate total MCR of either the SI or NI generators with the balance coming from the other interior region to meet the net load in the Coastal region. The net Coastal load is the difference between the Coastal load and the sum of Coastal dependable generation capacity and the portion of U.S. imports being delivered at Ingledow Substation.	The ILM flow is determined by dispatching the aggregate total DGC and (for intermittent resources) ELCC of either the SI or NI generators with the balance coming from the other Interior region to meet the net load in the Coastal region. The net Coastal load is the difference between the Coastal load and the sum of Coastal dependable generation capacity and the portion of U.S. imports being delivered at Ingledow Substation.

5	SI generation levels are reduced by the amount of U.S. imports being delivered at Nelway Substation even when modeling maximum SI generation conditions for this report.	The CE imports from U.S. are assumed to be delivered 11/14 at Ingledow Substation. SI generation levels are reduced by the amount of US imports being delivered at Nelway Substation even when modeling dependable SI generation conditions for this report.
6	Capacities identified for the F2006 Call plants and other IPPs that have EPAs but are not yet in service are not reduced to account for expected attrition to be consistent with a NITS application.	Capacities identified for the F2006 Call plants and other IPPs that have EPAs but are not yet in service are reduced to account for expected attrition.

BCTC comments that BC Hydro's request to the Commission to confirm the proposed CRP's are directionally appropriate is problematic because BCTC claims there is a need for some precision in the CRPs. BCTC submits that under the OATT, there is no mechanism that would permit BCTC to raise issues before the Commission regarding problematic aspects of new non-technical variations of a CRP that had been approved as "directionally appropriate". BCTC requires certainty in the contingencies in order to conduct facilities studies properly and plan the transmission system, and submits that although the OATT Decision recognized that a NITS application should be allowed some scope for contingencies, that scope should not extend to the definition of a range of options that have the effect of consuming ATC without ever arriving at a specific plan to address reasonable contingencies. (BCTC Argument, para. 32).

BCOAPO supports BC Hydro's position regarding the CRPs (BCOAPO Argument, para. 110).

CEC agrees that BC Hydro's request to submit the LTAP Base Case plan and two CRPs in the next NITS update/application should be approved (CEC Argument, p. 16).

The JIESC accepts BC Hydro's CRPs and believes they are adequate for present purposes (JIESC Argument, p. 21).

BC Hydro claims the need to ensure sufficient transmission capability to meet its planned contingency requirements is not a trade-off exercise and specifically:

> "While BC Hydro both expects and encourages BCTC to find ways to maximize the value of any remaining ATC for sales through Long Term Firm or Short Term Firm transactions and to find and capture any possible synergies between BC Hydro's NITS requirements and the potential sales of ATCs to third parties, BC Hydro does not expect its requirements to be traded off against any third party's requirements" (BC Hydro Argument, p. 118).

BCTC agrees that BC Hydro's legitimate needs are not to be traded off against the needs of others, but submits that the Commission has the responsibility to balance the obligation to plan and build the transmission system to meet forecast network loads and forecast generation resources against the rollover rights of Long-Term-Firm Point-to-Point transmission service customers (BCTC Argument, para. 29).

BC Hydro agrees that the Commission must be cognizant of and sensitive to the impact its approval of the CRPs may have on the ability of other customers to secure long-term firm capacity on the transmission system but points out that no party has objected to the CRPs, and there is no evidence to suggest that Commission approval of the CRPs would have a significant impact on a transmission customer's ability to secure long-term firm capacity (BC Hydro Reply, pp. 67-68).

Commission Determination

The contingencies considered by BC Hydro in the development of CRPs generally place greater stress on the use of the transmission system than the LTAP Base Case. Both CRPs utilize the high load forecast, and CRP2 further considers a shortfall in DSM response. The high load forecast and DSM shortfall act in the same direction and require more supply resources. It is difficult to separate the effects when looking at an aggregate demand. **The Commission Panel finds that the use of the high load forecast is an appropriate contingency to incorporate in the CRPs, but finds a further assumption of reduced DSM response to be redundant unless BC Hydro can show in a**

future application a difference in the effect on the CRPs between an increase in load forecast as compared to a reduction in DSM response.

The Commission Panel has concerns with the resource identification and distribution in the LTAP Base Case and the CRPs, and particularly with the structure of the 2007 Call resources shown in the LTAP Base Case and CRPs, which have been characterized as “smaller and regionally diverse projects” (T21:3281). BC Hydro provided substantial confirmation that the 2007 Call was likely to attract responses from “large projects” (T10:1327; T20:3042 and 3155-56). BC Hydro ultimately acknowledged that for the purposes of the NITS application, the 2007 Call probably should have been reflected as a large project (T21:3283). The Commission Panel notes this significant discontinuity between the expected next resource additions from the 2007 Call as compared to the resource structure in the LTAP Base Case and CRPs as derived from the 2005 Resource Options Report. The Commission Panel expects BC Hydro to align the resource additions shown in the LTAP Base Case and CRPs with its expectation of call structure and response in order to provide a sound basis for the NITS application review. The Commission Panel considers that creating contingencies from a Base Case that is not fundamentally sound should be avoided, as should be basing investment plans and transmission reservations upon those contingencies.

The Commission Panel remains concerned by the differences between the NITS planning assumptions and the IEP/LTAP planning assumptions as originally identified in Exhibit B-102 and described for a specific analysis in Exhibit B-146A. These differences make it difficult to have confidence in the assessment of impacts on the existing transmission system and the requirements for reinforcements and new transmission as identified by the IEP/LTAP process. The planning assumption addressing the consideration of intermittent resources is of particular concern, especially as more intermittent resources are added in the Interior. The use of the MCR could result in the need for increased transmission infrastructure that may have poor utilization factors. The Commission Panel notes that one of the design attributes of CRP2 is that 50 percent of the anticipated resources from the Lower Mainland/Vancouver Island region are moved outside that region, presumably to the Interior and elsewhere.

The Commission Panel finds the construction of the LTAP Base Case speculative because of the fuel mix diversity assumed in the response to the 2007 Call, given that the 2007 Call may be a large project call. The CRPs do not consider this alternate outcome to the 2007 Call, and hence do not sufficiently reflect the near-term resource contingencies that may face BC Hydro.

Although the assumptions listed above were for the purposes of the study in Exhibit B-146A, Appendix D, the Commission Panel is concerned that any assessment of transmission access impacts derived from the transmission implications identified in the IEP/LTAP process will be invalid because of the different planning assumptions utilized in the NITS application review. The Commission Panel expects BC Hydro's response to the determinations in Section 4.4.6 of this Decision will address this concern.

The Commission Panel accepts that BC Hydro's requirements should not be traded off against any third party's requirements, and although it is uncertain as to the impact the planning assumptions being applied in BCTC's analysis of BC Hydro's next NITS application will have on the ability of other customers to secure long-term firm capacity on the transmission system, the Commission Panel considers the preservation of the ability for BC Hydro to serve provincial loads to be an overriding concern. **The Commission Panel accepts the use of the LTAP Base Case and CRPs described in Exhibit B-1E and Exhibit B-55 for use in BC Hydro's next NITS update/application. With reference to the concerns noted regarding the composition of the LTAP Base Case and CRPs, the Commission Panel invites BC Hydro, at its earliest opportunity and preferably prior to the next NITS application, to submit for approval updated LTAP Base Case and CRPs that better reflect BC Hydro's expectations of future resource additions.**

With the approval of the CRPs, the Commission Panel finds it unnecessary to confirm whether or not the CRPs are directionally appropriate. The Commission Panel accepts BCTC's claim that there is need for precision and certainty in the composition of the CRPs in order for the transmission impacts to be accurately assessed.

In approving the LTAP Base Case and CRPs for the purposes of inclusion in BC Hydro’s NITS Application, as noted in Section 6 of this Decision the Commission Panel is not endorsing targets for specific resources or acquisitions.

8.0 PROJECT EVALUATION METHODOLOGY

8.1 Background

Section 8.5 of the LTAP, together with the additional project evaluation evidence (Exhibit B-11) filed by BC Hydro on June 30, 2006 (collectively referred to as the "Project Evaluation Methodology") outlined BC Hydro's proposed methodology for comparing the cost-effectiveness of resource options as they are developed and implemented. Following Information Requests from the Commission and Intervenors, BC Hydro filed responses thereto as Exhibit B-16. In the introduction to its evidence, BC Hydro states:

> "This evidence provides a policy level discussion of the impact of legislation and regulation on British Columbia Hydro and Power Authority (BC Hydro) and its application to project evaluation and customer rates. It provides a framework for review and includes a summary of BC Hydro's current rate of return on equity, weighted average cost of capital and discount rate.
>
> Its intention is to facilitate a review of the issues surrounding BC Hydro's project evaluation based on the regulatory construct for BC Hydro that must be applied in that review. It provides a policy level framework rather than a prescriptive means to undertake project evaluation" (Exhibit B-11, p. 1).

The issue of BC Hydro's cost of capital arose in the VITR hearing before the Commission, which in Order No. C-4-06 stated at page 181:

> "The Commission Panel is concerned by the apparent lack of a pre-existing policy on this issue within BC Hydro, particularly in light of the VIGP Decision, current government policy with respect to the role of the private sector in power development, and the statements by BC Hydro and BCTC regarding their receptivity to merchant transmission in the province. The Commission Panel concurs with Intervenors in this proceeding that the cost of capital issue may be very relevant to private sector developers of possible alternatives to BC Hydro or BCTC sponsored projects, and some certainty with respect to this issue is required in light of the significant investment required to identify, define and promote opportunities that may be of benefit to ratepayers. The Commission Panel supports BC Hydro's intention to file broad policy evidence on this matter in the IEP/LTAP proceeding."

8.2 Orders/Comments/Endorsements Sought

BC Hydro submits that its Project Evaluation Methodology appropriately compares the cost of resources with the value they provide (BC Hydro Argument, p. 6) and seeks general Commission comment on its Project Evaluation Methodology and specific endorsement by the Commission of the following elements of its Project Evaluation Methodology (BC Hydro Argument, pp.9-10):

- to endorse the use of the following financial parameters, recognizing that such parameters may change with changes in the forecasts of the relevant macro-economic indices or other relevant factors:
  - BC Hydro’s weighted debt cost as reflective of the cost of debt for project evaluation, in this proceeding represented as 6.7 percent; and
  - BC Hydro’s nominal weighted average cost of capital (“WACC”) of 8 percent, reflective of an environment of approximately 2 percent inflation.

In the VIGP Decision [BCUC Order No. G-55-03, *Reasons for Decision: Application for a Certificate of Public Convenience and Necessity for Vancouver Island Generation Project* (September 8, 2003)] the Commission stated at page 35: “The Commission Panel rejects debt-only financing as impractical for the cost of service analysis, considering BC Hydro’s expectations of system renewals. The Commission Panel agrees with Norske Canada that major capital projects should be considered to be financed at the Utility’s weighted average cost of capital.”

In addition to the comments and endorsements outlined above, BC Hydro also requests the Commission to revise this aspect of its VIGP Decision in order to recognize the difference between BC Hydro’s regulatory model, as prescribed by HC1 and HC2 which suggest an incremental revenue and rate impact of a BC Hydro project or acquisition being calculated on the basis that it will be 100 percent funded by debt (Exhibit B-16, BCUC 1.1.4, p. 2). BC Hydro reaffirms these requests in its Reply (BC Hydro Reply, p. 16).

8.3 BC Hydro's Two Cost-effectiveness Tests

BC Hydro testified that "the test we use for projects is the cost-effectiveness test … when we look at the financing costs we look at two financial tests. One is the impact on the ratepayer and the other one is an economic test. And we look at two as both indicators of what the financial impacts may be on BC Hydro and its customers" (T17:2607).

BC Hydro suggested that, in BC Hydro's case, cost-effectiveness tests should distinguish between:

(a) overall project economic evaluation, including risk; and

(b) cost causation to BC Hydro and its customers for revenue requirement and rate making purposes (Exhibit B-16, BCUC 3.1.4).

The main difference between the economic evaluation and rate impact analyses highlighted by BC Hydro in its evidence is the different discount rates used in the two analyses. Specifically, BC Hydro states that:

- for overall economic evaluation purposes, BC Hydro's WACC, based on Commercial Equity, should be used to determine discount rates and that this WACC is based on the ratio of debt to Commercial Equity, the latter being, in BC Hydro's case, the retained earnings component of the HC equity, as defined by HC2 and that, at current inflation rates, this WACC is 8 percent nominal;

- its debt: equity ratio is 80:20 for the purpose of calculating its WACC which it describes as the "risk-adjusted cost of capital" in that it recognizes the risk inherent in the overall business of BC Hydro as a utility, while project-specific risk is accounted for through sensitivity analysis; and

- for revenue requirements and rate impact purposes, the incremental impact of a project should be calculated on the basis that it will be 100 percent funded by debt. BC Hydro states that this reflects the practical reality of BC Hydro's access to funds, and that debt is the only mechanism available from which to raise funds in the short term, while equity is accumulated over the long-term based on the opening HC equity balance and the allowed return on [its] equity, both of which are independent of any capital expenditures (Exhibit B-16, BCUC 3.1.4).

BC Hydro suggested that the WACC can be considered to be "risk-adjusted" in that it recognizes the overall company risk of BC Hydro, given the nature of its business, but that it does not reflect specific project risk, nor does the rate impact analysis take into account project risk by using the cost of debt only. While it is possible to vary discount rates (by adding a further project-related risk premium) to reflect project-specific risk, BC Hydro stated that it chooses not to adopt this approach, but to address project risks through sensitivity analysis and contingencies (Exhibit B-10, BCUC 2.403.2; T11:1640) and to review explicitly such possible risks as higher than expected costs, schedule changes, and lower demand (Exhibit B-16, BCUC 3.1.4).

BC Hydro submits that its Project Evaluation Methodology is structured from the point of view of the customers of BC Hydro, current and future and that structuring from this point of view aligns the Project Evaluation Methodology with the *UCA*, HC1 and HC2. At the planning level of the IEP/LTAP, there are few material distinctions between the impact of projects on (a) BC Hydro and (b) customers of BC Hydro who would be expected to pay for the additional services being acquired. Evaluations underpinning the 2006 IEP/LTAP, including the project evaluation evidence, are based on present worth or revenue requirement analyses that reflect the time value of money. While there may be differences in the short term, in a long-term analysis, there should only be material differences between what customers of BC Hydro pay and what BC Hydro pays if there were to be a non-standard event such as a disallowance of costs in a revenue requirement proceeding or an event that would trigger a special payment to or from the shareholder (BC Hydro Argument, pp. 119-120).

8.4 The Cost of Capital

8.4.1 Weighted Cost of Capital

BC Hydro stated that it proposes "to continue to use a 6 percent real WACC for the economic analysis of projects, which translates to approximately 8 percent nominal, given current inflation. This reflects the underlying risk-adjusted cost of capital." BC Hydro set out the relative weightings and cost of the capital components to determine its overall WACC.

	$ million	Weight	Cost	Total (Nominal)
Debt	6,627	80%	6.70%	5.4%
Equity	1,688	20%	13.13%	2.6%
WACC	8,315			8.0%

BC Hydro stated that "Debt" comprises its outstanding borrowings at March 31, 2005, and that "Equity" comprises retained earnings at that date (Exhibit B-11, p. 15; Exhibit B-16, BCUC 3.9.1).

8.4.2 Equity

BC Hydro differentiated between "HC Equity" as described below and "Commercial Equity" which to describes the earnings retained in its business.

BC Hydro submits that it is has no outstanding common shares, has never issued common shares and lacks the authority to issue common shares. Since it cannot raise equity and since its retained earnings will grow each year in accordance with the HC formula regardless of the level of capital expenditures it undertakes, BC Hydro submits that any rate impact analysis must be developed on the basis the project will be funded by 100 percent debt (T18:2780; BC Hydro Argument, p. 123).

BC Hydro noted that under HC2 the Commission is directed to set rates to give BC Hydro the opportunity to earn a specified return on its equity as defined in HC2 ("HC Equity"), which comprises:

- retained earnings which should increase by 15 percent of distributable surplus each fiscal year;
- deferred revenue which represents amounts received under the Skagit River Agreements which expire in F2066 at which time the amount deferred will be zero;
- contributions arising from the Columbia River Treaty which are reducing by $9 million each year and will be zero by F2025; and

- contributions in aid of construction which from F1995 toF2005 increased by $118 million for an average increase of almost $12 million per year.

BC Hydro stated that the HC Equity is unrelated to BC Hydro's capital assets and no consideration has been given to HC Equity as a percent of assets and that it is very unlikely that HC Equity will eventually reach 100 percent as BC Hydro will, at a minimum, have an ongoing requirement for significant sustaining capital to ensure the reliability of the integrated system (Exhibit B-16, BCUC 3.6.2).

BC Hydro filed three 20-year forecasts of its debt to equity ratios under three scenarios:

(i) capital expenditures of $608 million per year;

(ii) capital expenditures of $1216 million per year; and

(iii) capital expenditures of $1216 million for 10 years and $608 million thereafter,

to demonstrate that the change in level of capital expenditures does not change the total HC Equity or Commercial Equity, although the ratios change as follows:

F2026		**Scenario i**	**Scenario ii**	**Scenario iii**
HC Equity	%	54	35	48
Debt	%	46	65	52
HC Equity	$million	5906	5906	5906
Commercial Equity	$million	3387	3387	3387

(Exhibit B-16, BCUC 3.32.7)

BC Hydro stated that it used a 80:20 debt to equity ratio to calculate its WACC because its debt to HC Equity ratio of approximately 70:30 is "skewed" by the inclusion of what it considers to be three non-commercial elements of HC Equity, being deferred revenue, contributions arising from the Columbia River Treaty and CIAC and by excluding these three elements it derives a ratio of 80:20

between debt and what it considers its only commercial element of equity, namely its retained earnings (Exhibit B-16, BCUC 3.13.3).

BC Hydro stated that under HC2 it is directed to pay 85 percent of its annual earnings each year to the Provincial Treasurer but that this obligation is reduced if the required payment would cause its debt to HC Equity to exceed 80:20, to the greatest amount that BC Hydro could pay without exceeding the 80:20 ratio ((Exhibit B-11, Appendix 2).

8.4.3 Cost of Equity

BC Hydro stated that its current cost of equity is its F2007 allowed return of 13.13 percent calculated as follows:

2006 approved return for Terasen	8.8%
Terasen’s effective income-tax rate for 2006	33.2%
Grossed-up pre-income tax rate of return	13.13%

(Exhibit B-11, p. 5)

8.4.4 Cost of Debt

In both its WACC and its rate impact analysis, BC Hydro stated that it uses the embedded cost of its debt, namely 6.7 percent. It testified that its current cost of issuing 20 to 30 year debt was in the 4.60 to 4.65 percent range (T19:2706).

BC Hydro indicated that its 6.7 percent debt cost is its weighted average cost of debt, derived by dividing consolidated finance charges by average debt outstanding and that its finance charges include all items which impact the cost of its debt, including such items as interest during construction, foreign exchange movements and its activities with respect to adjusting the fixed versus floating rate date mix (Exhibit B-16, BCUC 3.26.5).

BC Hydro testified that it uses its embedded cost of debt rather than the incremental cost of debt because "we look at the debt as an entire portfolio and we manage the fixed floating mix based on what we think is the best, given market conditions at the time, independent of when we happen to issue debt" (T19:2908); and "Well, we do manage the debt and we look at the debt as a portfolio, and we manage our fixed floating mix based on what we think is optimal from a risk return perspective. And that's independent of when we happen to issue and the tenor at this we happen to issue. So just because we issue a bond today at 4-60 and we replace one that happened to mature that day and that's why we issued a new one, that doesn't in our view directly impact the effect on the customer of a particular capital project" (T19:2907).

8.5 Economic Evaluation of Aberfeldie

BC Hydro included with its evidence an example of a project evaluation completed for the Aberfeldie redevelopment project. BC Hydro noted that this evaluation included the following:

- rate impact analysis;
- levelized cost analysis;
- Net Present Value (NPV) analysis; and
- comparison to acquisitions

and that the key variables it examined included capital costs, operating costs (such as water rentals, taxes, operating and maintenance costs and water license compliance fees), borrowing costs, decommissioning costs and equipment performance (Exhibit B-11, p. 16).

BC Hydro stated that the rate impact analysis was prepared assuming 100 percent debt financing and a depreciation term of 50 years. The results varied with each scenario given different levels of capital costs and other factors. The rate impact identified the difference in customers' rates between redeveloping Aberfeldie and not doing so; and thus indicated the incremental rate impact of the project.

BC Hydro indicated that its levelized cost analysis identified the average unit cost of electricity from the facility, post the redevelopment, over a 25 and 50 year life, and included variations for different capital and financing costs.

BC Hydro indicated that its NPV analysis was prepared over a 20-year period using a number of different electricity price forecasts, which represented alternative sources of electricity such as market purchases, and that the analysis was again completed using a number of different scenarios.

BC Hydro stated that it performed an evaluation to identify what might have been the bid price for Aberfeldie were it to have been bid into the F2006 Call and that the evaluation included the characteristics of the different sources of supply such as reliability, energy shape, dispatchability, location, etc. All these analyses were considered together taking into account the sensitivities and risks around them in order to assist in the decision-making as to whether to proceed or not with a specific investment, in this case Aberfeldie.

BC Hydro stated the Aberfeldie analysis consistently used 6.7 percent as the cost of debt for the assessment of rate impacts and project evaluation, and that its other project evaluation work used an 8 percent WACC to reflect its overall risk-adjusted cost of capital. BC Hydro stated the use of the WACC and other sensitivity testing enabled a comparison of different options and provided the ability to reflect unidentified project risks within this discount rate (Exhibit B-11, pp. 16-17).

8.6 Project Evaluation Criteria

Most Intervenors submitted argument on BC Hydro's Project Evaluation Methodology.

The JIESC observes that the existing degree of uncertainty regarding BC Hydro's Project Evaluation Methodology was clearly demonstrated in this proceeding, in that information requests relating to the 64 pages of Exhibit B-11, BC Hydro's Project Evaluation Evidence, generated 863 pages of information responses, and that was after many of the issues had already been discussed in the VIGP, Duke Point, VITR, 2006 CFT and F2007/F2008 RRA proceedings, and that cross-examination on these issues was extensive (JIESC Argument, p. 21).

The JIESC urges the Commission to codify the following issues to give parties clarity and BC Hydro direction by ordering a particular treatment or by declaring a treatment that will be presumed unless there is good reason for another treatment with respect to:

- the real and nominal discount rate to be used for evaluations must be the same for IPPs and BC Hydro;
- the relevant costs for comparisons between projects and between IPP, DSM and Resource Smart are the costs that reflect what IPPs receive and what ratepayers pay, including all taxes (e.g. water rentals) and the actual BC Hydro incremental cost of capital (100 percent debt);
- appropriate risk adjustments for DSM and Resource Smart must be made to give them comparable cost certainty to IPP projects, with P90 capital estimates being one solution;
- asset life assumptions (BC Hydro should use actual depreciation rates for Power Smart and Resource Smart);
- inflation assumptions must reflect actual expectations based on contract or reasonable expectations or a combination of both;
- Site C comparisons with IPPs, DSM and Resource Smart; and
- the appropriate principle for comparing projects is cost effectiveness not establishing a level playing field. Every project has its advantages and these should be capitalized on, not hidden by assumptions intended to create a "level playing field" (JIESC Argument, p. 22).

Of all Intervenors, IPPBC takes the strongest position against BC Hydro's evidence on Project Evaluation and BC Hydro's requested comments and endorsements.

IPPBC submits that it has long asserted that the competition between the alternatives that BC Hydro has for supplying electricity to its customers should be held on as level a basis as possible, and that the benefits from competition accrue to IPPs, BC Hydro and BC Hydro's customers (IPPBC Argument, p. 2).

IPPBC submits that progress has been made to level the playing field but that one area where biases still exist and that needs work is BC Hydro's general project evaluation methodology which "while appearing to have conceptually adopted a weighted average cost of capital approach, still clings to an illusion that BC Hydro projects can be evaluated on the basis of 100 percent debt financing," which will lead the ratepayers into thinking that Resource Smart projects will be more cost-effective, relative to IPP projects, than they are in reality (IPPBC Argument, p. 2).

IPPBC submits that the level playing field does not contradict the objective of finding the best value or most cost-effective products for BC Hydro's customers, and that illuminating the customers' value choices more clearly is one of the outcomes of the level playing field. The choices must be based on the true costs to the customers, not costs based on a cost of capital that will not in fact be used to determine their future rates.

IPPBC submits that each IPP includes its true cost of capital in its bid price, and that bid price will be used to set the customers' future rates. Similarly, the future rates that will be paid by customers in respect of a Resource Smart project will be based on BC Hydro's future debt and equity, not merely on its cost of debt and in this regard customers deserve a full disclosure at the outset of what those costs are likely to be. Calculating the hypothetical rates based on 100 percent debt, does not give this full disclosure (IPPBC Argument, p. 2). IPPBC argues that:

> "…BCH is not much different from most commercial corporations of a similar size. A typical large commercial corporation does not access the equity market in order to make a reasonable level of capital investment each year. Its equity grows by retention of earnings, just the same way that BCH's does. At the given moment when a capital investment is paid for, the actual cash comes from increasing debt, exactly the same as BCH's does. When equity dollars are accumulated from earnings, the actual cash is used to pay down the debt, exactly the same as BCH does… In short, there is no difference between a typical large commercial corporation and BCH with respect to the normal ebb and flow of cash from debt and equity, and into capital investments, whenever they are made. The only difference would occur if the corporation wanted to make a very large or risky investment relative to its size. In that case the commercial corporation would have access to the equity markets, whereas BCH would only be able to indirectly get the funds from its shareholder, spread over time, by driving its debt/equity ratio above 80/20, which results in a withholding of dividends, and hence an accumulation of equity at a faster rate. Still, this is not a

> huge difference between BCH and a similarly sized commercial corporation, and not one that is forecast to occur in the next 20 years. It is true, as BCH observes, that when an actual capital investment is paid for, only debt increases. However, it is also true that, as the equity dollars are accumulated from earnings, those dollars will replace some of the debt, thus maintaining the balance sheet in approximately the same ratio of debt to equity" (IPPBC Argument, p. 5).

IPPBC submits that over the period F2007 to F2009 BC Hydro will spend $3.5 billion on capital expenditures with only a $2 billion increase in debt, and that this 58/42 marginal debt/equity ratio will persist over the next 20 years, with the result of reducing debt from 70.1 percent to 64.8 percent over that period (IPPBC Argument, p. 6). IPPBC submits that BC Hydro's WACC should be computed using the 58/42 ratio, and that BC Hydro should use its WACC, calculated in this fashion, for all its project evaluations.

The BCOAPO addresses the level playing field issue and submits that "IPPs have adopted the refrain that the selection of resources, as between BC Hydro's own projects and contracted private sector projects, must operate on a 'level playing field'. It is important that this metaphor be used carefully so as to provide more clarity than obscurity to the question" and "… the Commission would fall into error were it to permit other interests (such as the commercial interests of IPPs) to override the interests of utility customers. The IPPBC seeks to actually tilt the playing-field to compensate for the inherent disadvantages of private sector developers. The Commission should not indulge this" (BCOAPO Argument, paras. 112, 117).

The CEC submits that "BC Hydro has done a good job of articulating its evaluation approaches. The evaluation methodology has internal integrity and is largely consistent in its use across the range of alternative projects and programs BC Hydro must consider. In particular, as they are used to evaluate its LTAP decisions, where they are particularly relevant to this hearing, they are appropriate" (CEC Argument, p. 70).

CEC also raises the issue of trade income risk in Argument. Specifically, CEC submits that given the definition of trade income and the cap on trade income which accrues to ratepayers under HC2, an investment which results in trade income which does not go to the benefit of the ratepayer but rather to the shareholder is an investment which ratepayers should be entitled to scrutinize in order to ensure the investment is cost-effective (CEC Argument, p. 80). CEC draws linkages to the Transfer Pricing Agreement between BC Hydro and Powerex and argues that BC Hydro "has not turned its mind to the issue of the impact of the transfer pricing agreement and the trade income account on the appropriate risks to be undertaken when considering investments in the expansion of the electric system for which customers will be asked to pay" (CEC Argument, p. 81). CEC uses the Revelstoke business case as an example of problems associated with the treatment of trade income in BC Hydro's Project Evaluation Methodology. CEC requests that:

> "…the BCUC direct that as a condition of approval of this $12.5 million investment, BC Hydro, as part of their CPCN application for Revelstoke and other material CPCN processes, provide an evaluation as to what changes can be made to the transfer pricing agreement between BC Hydro and its subsidiary Powerex which will more fairly accrue the benefits of these significant new investments to ratepayers in relation to trade income as opposed to the shareholders in the event that these investments and Resource Smart initiatives create new opportunities for Powerex. The CEC is not asking that specific changes be made at this time but a direction that this issue be considered in future filings with the BCUC" (CEC Argument, p. 87).

The JIESC would like to see the BCUC require BC Hydro to include a full assessment of potential trade benefits of future generation and transmission projects in capital plans, LTAPs, IEPs and CPCNs. In some cases these benefits can be substantial and may make the difference between a project languishing or being expedited to the ultimate benefit of ratepayers (JIESC Argument, p. 2).

BC Hydro suggests that CEC's submission "…treads into an issue of important Provincial Government policy that has already been the subject of a significant hearing before the BCUC [the Heritage Contract Inquiry]; a report by the BCUC; and a legislated Government response [the Heritage Contract]" (BC Hydro Reply, pp. 45-46). Specifically, BC Hydro argues that CEC's submission appears to seek to reallocate the trade benefits arising from BC Hydro's system to the advantage of BC Hydro's customers and to the disadvantage of BC Hydro's (and thus Powerex's) shareholder, circumventing Provincial Government electricity policy.

In addition, BC Hydro argues the submission "…inappropriately links the requested relief with a specific project, and the approval process in respect of it… Ignoring the question of whether the BCUC has the ability to condition the approval of an expenditure pursuant to its section 45(6.2) (b) review of a public utility plan, a matter that BC Hydro respectfully submits is a live issue, it is not appropriate for CEC to couple the requested direction with the Revelstoke Unit 5 funding relief sought in this proceeding" (BC Hydro Reply, pp. 46-47). BC Hydro argues the issue raised by CEC arises not from any one project, but rather by the entirety of BC Hydro's system being available from time to time for electricity trade purposes and opposes CEC's specific request. BC Hydro agrees that the quantification and allocation of expected benefits should be analyzed as part of the project development process and undertakes to include in future facilities applications, to the extent possible, an enumeration of the expected benefits for the particular project, and the anticipated allocations of such benefits, commencing with the Revelstoke Unit 5 CPCN application (BC Hydro Reply, p. 48).

Terasen Gas submits that these costs of capital and project evaluation criteria are unique to BC Hydro and that the Commission's findings in these matters should not be determinative with respect to other utilities that the Commission regulates. Terasen Gas submits that in spite of the restrictions imposed by the special directions, the components of the HC Equity will provide a significant source of funding for capital projects over the next 20-years for which debt financing will not be required, and that based on BC Hydro's own evidence HC Equity is expected to provide 42 percent of the incremental funding requirements at forecast capital spending levels over the next 20 years. Terasen Gas also points out that BC Hydro acknowledges that it manages cash on a pooled basis and does not link stream sources of funds such as retained earnings, debt issues or cash flow from operations to specific uses such as capital expenditures. Based on the weight of evidence that HC Equity provides significant sources of funding in support of capital spending over the long-term and the other factors cited above, Terasen Gas submits that there is no compelling reason for the Commission to alter its finding in the VIGP Decision that the capital projects should be considered as being funded by a combination of debt and equity (Terasen Gas Argument, paras. 29-31).

CPC filed the evidence of Dr. Shaffer entitled “Capacity Considerations and Other Limitations in the F2006 Call: Recommendations for Future Resource Acquisitions” (Exhibit C31-6). Section 3.3 of the evidence, entitled “No recognition of Water Rental Benefits” is seven lines long and concludes: “BC Hydro does not make any adjustment for water rental payments in its evaluation process. That overstates the real cost of hydro power to British Columbians, which is the total cost less the water rental benefit paid to the government.” This relatively minor observation created a significant amount of debate both in the form of information requests, cross-examination and argument.

CPC’s evidence was characterized by BC Hydro and several Intervenors as advocating “social costing.” However, in Argument, CPC submits that its “evidence does not contain a ‘social costing’ proposal” (CPC Argument, p. 9). The CPC states: “The evidence focuses on water rentals because including them as a cost in the comparative evaluation of alternative sources of supply is a very clear and measurable bias in an evaluation from a taxpayer as well as a rate payer perspective. Water rentals are a benefit to taxpayers. Failing to recognize that benefit will result in the overstatement of the net social costs of hydro projects. This bias is particularly significant for large hydro projects that pay rentals some five times the water rental rate on small hydro projects” (Exhibit C31-7, BCUC 1.3.1).

The CPC continues: “There are other taxes for which social adjustments could be made to ensure selection of the lowest cost sources from a taxpayer as well as ratepayer point of view. In principle, adjustments should be made for those taxes which are incremental and which are not offset by incremental government costs. In practice, adjustments should only be made where the incremental tax benefit can be reliably measured and where there are likely to be significant differences among alternative projects (where recognizing them could materially affect the evaluation)” (Exhibit C31-7, BCUC 1.3.1). Such taxes would include motor fuel tax, but no provincial royalties on natural gas used to generate power as the former is incremental and the latter represents a payment for the depletion of a non-renewable resource. The CPC does not recommend adjustment for income taxes payable by IPP owners or for sales taxes.

The CPC offers the following observations on externalities:

> "Where negative environmental externalities can be measured on a reasonably reliable basis (e.g. air pollution damage or offset costs), it would be worthwhile to include those social costs in the evaluation of alternative sources. The same applies to positive environmental externalities (e.g. the fisheries and related cost mitigation benefits from hydro-electric plants that reduce in-stream total gas pressures ("TGP") below levels harmful to fish). It is preferable where possible to recognize the specific benefits a project may offer rather than to provide a common green credit regardless of the magnitude and significance of the benefits.
>
> Explicit recognition of the negative and positive externalities a project may have provides a transparent basis for assessing the environmental trade-offs arising from different sources of electricity supply. … This … social costing … methodology was used to evaluate bids under the December 1994 Request for Proposals for the Supply of Electricity for the BC Hydro Integrated System" (Exhibit C31-7, BCUC 1.3.1).

Dr. Shaffer testified:

> "With respect to environmental externalities, I recognize the point and it's clear in here that it is difficult. A social costing has challenges to it. If what one means by that, putting precise monetary values on the various elements of each environmental externality, where it can be done reliably and reasonably, I think it's worthwhile to do. My own preference and in the course that I teach, I would recommend more of a multiple account approach where you look at the tradeoffs and the critical values" (T22: 3525).

Dr. Shaffer summarizes his testimony on water rentals:

> "Should we forego the project that can produce power at $71.00 because government's put in a $5.00 water rental? That's the question I was getting at. Was it -- and quite honestly, it was meant to be a relatively minor part of the evidence, but it was -- and it wasn't even meant to be just large hydro versus small hydro. It's hydro versus non-hydro, or hydro versus projects where those kinds of adjustments aren't needed or wouldn't be significant.
>
> So that's the question in this process. And if you're going to ignore the fact that we could actually be producing electricity at $71.00, you know, before the tax -- the pure tax transfer, we'd rather spend $75.00. I think that, in my view as an economist, I'd say that's not in the public interest. That's all" (T22: 3567).

BC Hydro submits that the Commission has the mandate to consider environmental and social costs that are likely to emerge as costs for utilities and their customers under various sections in the UCA (Exhibit B-10, BCOAPO 1.3.1). BC Hydro categorizes CPC's evidence as "CPC's Social Costing Proposal" (BC Hydro Argument, pp. 129-132) and submits that the Commission should place no weight on this portion of the CPC's evidence. BC Hydro states that the current government policies (the 2002 Energy Plan and the 2003 Resource Planning Guidelines) are quite clear on environmental and social matters, and have replaced the 1992 Provincial policy and 1993 Guidelines, which required social costing. BC Hydro also submits that using social costing in integrated resource planning as a project evaluation tool was not part of current industry best practices.

IPPBC submits that it supports CPC's position provided that full social costing be applied and not the selective one suggested by the CPC. IPPBC observes that the establishment of a balanced set of social costing criteria "would be a long laborious process, the costs of which would at this time, outweigh the benefits" (IPPBC Argument, pp. 45-46).

The JIESC submits CPC's evidence that water rentals should not be included in comparing costs of bids as they amounted to a "social cost" or transfer payment should be rejected, principally on the basis that the full costs are the costs that will be paid by ratepayers. The JIESC also notes that neither BC Hydro nor the Commission has a mandate to give special treatment to "social costs" taxation and transfers. Furthermore, BC Hydro is subject to a clear mandate for low cost rates in the Energy Plan, and special treatment for water rentals and other social costs would run contrary to that requirement, increasing rates beyond what they would be if the lowest full cost project were chosen. In addition, the JIESC submits that administering bids where social, taxation and transfer costs are excluded from the bid selection process adds an unnecessary and unwarranted degree of complexity in the CFT evaluation process as detailed IPP costs would need to be known and all bids would have to be adjusted. The exclusion of water rentals cannot be approved without evaluating the costs and economic benefits of other resources associated with royalties and taxes and who knows what else that might be subject to a claim for exclusion as a social cost or benefit (JIESC Argument, p. 19).

The CEC submits that it supports the BCUC's determination in the VIGP Decision that the Commission is limited in considering environmental and social impacts to those that are likely to emerge as costs to the utility and their customers and or are encompassed in the cost-effectiveness test and agrees with BC Hydro that it does not have a mandate to apply social costing and replace the customer perspective with a societal perspective (CEC Argument, p. 68).

Commission Determination

The Commission Panel finds that BC Hydro's Evidence on its Project Evaluation Methodology, the information requests and the cross-examination, all focused on two issues: (i) what was the purpose of the evidence, and (ii) what discount rates should BC Hydro use for its analyses.

<u>The purpose of the evidence</u>

The Commission Panel finds that the purpose of BC Hydro's Project Evaluation Methodology is to demonstrate to its Owner, Board of Directors, Regulator, Ratepayers and Stakeholders that acquisitions, whether Resource Smart, Power Smart, or IPPs, are cost-effective and thus in the public interest and that, to make this demonstration, BC Hydro must use a methodology that takes its individual corporate status and blends it with generally accepted corporate finance principles to arrive at an end result that is both comparable and comprehensible.

Typically the end result of a project evaluation is the expression of a PV or a levelized cost of energy or capacity. Both calculations require the use of a discount rate, and both calculations require a stream of cash flows to apply the discount rate to.

The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not

found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro.

BC Hydro's evidence is not particularly clear with respect to the differences in the underlying cash flows used in its economic analysis and ratepayer impact analysis. Rather, in its evidence, BC Hydro focuses mostly on the different discount rates it uses in the two analyses, namely the WACC in the economic analysis and the embedded cost of debt in the ratepayer impact analysis. While not explicit, the Commission Panel assumes that the economic analysis considers cash flows from the perspective of BC Hydro, while the ratepayer impact analysis considers cash flows from the perspective of the ratepayer. However, as noted by BC Hydro, at the planning stage there are few material differences in the impacts on BC Hydro and customers, because evaluations are based on present worth or revenue requirements analyses, and in the long-run differences would only arise in a non-standard event such as a disallowance of costs in revenue requirements (BC Hydro Argument, p. 119). In the case of acquisitions from IPPs, there will be no significant difference in cash flows to BC Hydro and cash flows to ratepayers since both will be determined by the pricing in an EPA. In the case of BC Hydro projects, including DSM, there may be differences between cash flows from the perspective of BC Hydro and from the perspective of ratepayers, since the latter will depend in part on accounting treatment of capital expenditures for rate setting purposes (e.g., depreciation rates), and may include other considerations such as interest during construction, sunk development costs, or overhead costs allocated from other departments. The Commission Panel considers the economic analysis the more important analysis and should be reasonably correlated with the incremental rate impacts attributable to projects.

The Commission Panel accepts that multiple tests may be used to evaluate projects, but some consideration must be given to a) the incremental information offered by each additional test; and b) the ability of that information to alter a decision. Where two tests produce very little difference in the ranking of projects, it is unnecessary and potentially confusing to use both tests. One will suffice. Even where the ranking of projects may vary under different tests, if one test always takes precedence, the second test has little relevance in decision making. It is only important to consider tests that provide significant additional information (in distinguishing among projects) and may in fact be used to alter decisions.

Besides the differences in discount rates, which the Commission Panel discusses below, BC Hydro has provided no evidence of other significant differences in the information provided by the economic analysis or ratepayer impact test, or how it would in fact use the results of the two tests to make decisions if they produced alternate rankings of projects.

The suitable discount rate(s)

The Commission Panel accepts BC Hydro's arguments regarding the actual operation of HC1 and HC2, and the minimal linkage between capital spending and actual equity levels in BC Hydro. The Commission Panel does not accept that HC1 and HC2 always result in 100 percent debt financing. As acknowledged by BC Hydro, there are situations when capital expenditures could affect the level of equity in the company (either immediately in the year in which they occur, or in subsequent years by reducing BC Hydro's room to borrow for future capital expenditures). As such, it is not appropriate to conclude that the long-run incremental cost of funds to BC Hydro is always 100 percent debt under HC1 and HC2. Ratther, the long-run incremental cost of funds should be established through occasional forecasts of capital expenditures and the availability of debt financing to BC Hydro. **However, based on forecasts of capital expenditures and debt levels prepared by BC Hydro in this proceeding, the Commission Panel accepts that for the foreseeable future incremental capital projects will effectively be financed with 100 percent debt.**

While the Commission Panel accepts this as an outcome of the actual mechanical operation of HC1 and HC2, the Commission Panel is sympathetic to the arguments made by Terasen and IPPBC regarding the intention of HC1 and HC2. The Commission Panel agrees with Terasen that HC Equity will in fact be a source of funds for capital expenditures in coming years. However, the Commission Panel also agrees with BC Hydro that given the way HC1 and HC2 work in practice, there is no direct linkage between the level of capital spending and the level of equity in the company. As a result, the Commission Panel agrees with BC Hydro that, based on current capital spending projections and debt limits, capital expenditures by BC Hydro can only affect debt levels in the company and therefore the cost of debt represents the opportunity cost of these expenditures, either via increasing debt levels or reducing the rate at which debt would otherwise be retired. The Commission Panel also agrees with IPPBC's characterization of the role of retention policies in commercial corporations to fund normal capital investment. However, since BC Hydro's owner has provided no policy statement regarding the intention of HC1 and HC2 and has not intervened in these proceedings to clarify its policy intention, the Commission Panel must accept the evidence of BC Hydro regarding the operation of HC1 and HC2 and their effect on the impact of incremental capital expenditures on ratepayers.

With respect to BC Hydro's cost of debt, the Commission Panel notes that on one hand BC Hydro argues against using the WACC in establishing rate impacts because the WACC does not reflect incremental financing impacts, and on the other has chosen to use an embedded (historical) average cost of debt in establishing rate impacts. The Commission Panel rejects BC Hydro's reasons for using its embedded cost of debt to perform any economic analysis and finds that its debt portfolio management approach and its fixed/floating mix are not relevant for the evaluation of a proposed project. Similarly the fact that a 50-year life project has been financed by debt with a 20-30 year tenor, is no reason to ignore the incremental borrowing rate and use the embedded one. BC Hydro borrows at rates that reflect the Provincial Government's credit rating and current nominal interest rate on 20 to 30-year debt for BC Hydro, and thus its ratepayers, is approximately 4.60 percent per annum. **The Commission Panel concludes this is the appropriate discount rate for BC Hydro to use to evaluate resource options under the current assumption of 100 percent debt financing**.

Throughout this proceeding, BC Hydro argued that the appropriate discount rate to be used in the ratepayer impact analysis is its incremental opportunity cost of capital, which it argued is 100 percent debt. BC Hydro made no distinction between the cost of funds assumed to establish a set of cash flows for BC Hydro-funded projects and the rate at which the different cash flows associated with BC Hydro projects and IPP projects in the ratepayer impact analysis should be discounted. IPPBC took exception to BC Hydro's assumption of 100 percent debt financing, but made no fundamental distinction between BC Hydro's opportunity cost of capital and the appropriate discount rate for discounting flows in the ratepayer impact analysis. No other intervenors took exception with BC Hydro's fundamental approach to the discounting issue. Accordingly, the Commission accepts the use of BC Hydro's opportunity cost of capital in the ratepayer impact analysis, agrees that at the moment the opportunity cost of capital should reflect 100 percent debt financing, and finds that the incremental nominal cost of debt, currently 4.6 percent, is the more appropriate assumption for assessing incremental impacts.

BC Hydro advocates the use of its WACC as the discount rate for its economic analysis. Again, BC Hydro makes no distinction between the opportunity cost of capital and the discount rate in its evidence. The main rationale offered by BC Hydro for using the WACC is to reflect corporate-level risk. While it is possible to vary discount rates (by adding a further project-related risk premium) to reflect project-specific risk, BC Hydro's practice of addressing risks through sensitivity analysis and contingencies, to explicitly review possible risks, such as higher than expected costs, schedule changes and lower demand is perfectly acceptable and the Commission Panel supports the use of project-specific sensitivity analysis and contingencies as a more explicit approach to deal with risks. The Commission Panel also notes that BC Hydro has not provided any evidence how a discount rate based on 80/20 debt equity ratio adequately captures the risks associated with its projects, and has also not suggested applying different discount rates for different types of projects (e.g., DSM vs. Resource Smart), which would seem logical given the different types of risks associated with each type of investment. The Commission Panel therefore finds no reason to use different discount rates in different tests, although multiple discount rates may still be considered in sensitivity analyses on each test.

Accordingly, the Commission Panel finds no justification for the use of different discount rates for the economic analysis and the ratepayer impact analysis. The Commission Panel considers the issue of risk to be dealt with adequately through the sensitivity and scenario analysis. However, the Commission Panel does continue to see value in sensitivity analyses around a single discount rate.

Level Playing Field

With respect to the level playing field issue, the Commission Panel agrees with BC Hydro, JIESC, BCOAPO, and CEC that the Project Evaluation Methodology must consider the actual costs, benefits, risks and other characteristics of individual projects that may be relevant to cost-effectiveness, and should not seek to artificially compensate for real differences in project impacts, including possible differences in the cost of capital between BC Hydro and other developers. With respect to the cost of capital, BC Hydro projects will clearly have an advantage as a result of 100 percent debt financing and access the Province's high credit rating.

Aberfeldie

In the Commission Panel's view, BC Hydro's effort to devise a price it might have bid Aberfeldie into the F2006 Call was not helpful, and the Commission Panel does not believe that any purpose will be served by requiring BC Hydro to bid its Resource Smart or DSM projects into future calls. The Commission Panel also finds that the Aberfeldie analysis introduced by BC Hydro illustrates well the potential confusion created by the use of many different impact indicators with no clear understanding of the different information provided by each or how trade-offs may be made among the different impacts. The Commission Panel expects BC Hydro to provide clearer explanations to the Commission and stakeholders regarding the different kinds of information provided by each impact indicator and to limit its analyses to those indicators that provide incremental information. Furthermore, the Commission Panel expects BC Hydro to provide a better explanation of how the different impact indicators are used in its final decisions and to rationalize any trade-offs it has made among the different tests. The Commission Panel would also expect some consistency in how BC Hydro makes trade-offs across different types of impacts in different applications.

Site C

The Commission Panel has considered the JIESC's submission that all projects be evaluated against the cost of power from Site C, but is not persuaded that such an exercise would be of any value at this time given the lack of clarity from the provincial government regarding BC Hydro's ability to consider development of Site C.

Water Rentals and "Social Costing"

The Commission Panel agrees with previous determinations by the Commission that detailed consideration of social costs is required only where there is a risk these may become financial liabilities for ratepayers (e.g., GHG emissions). Social costs may also be considered at a screening level to ensure Applicants have identified and selected alternatives that have similar financial costs for ratepayers but lower social costs.

On the narrower issue of whether BC Hydro's evaluation process should make an adjustment for water rental payments, the Commission Panel finds that the entire project evaluation exercise centres around what costs BC Hydro and its ratepayers will bear. Unquestionably water rental payments are a cost that BC Hydro and its ratepayers will pay, and the Commission Panel finds that BC Hydro's approach (in making no adjustments) is correct. In addition, taking a broader view of policy as opposed to practice, the Commission Panel finds that adjusting for such payments may well have the potential of frustrating the purposes that various levels of government had when they introduced them (e.g., differential water rental rates on different kinds of projects).

DSM Tests

The Commission Panel confirms Directive 60 from the F05/06 RRA Decision, which accepts three DSM cost/benefits screening tests as appropriate – Utility Cost Test, All Ratepayers Test and Non-Participant Test.

<u>Trade Income</u>

The Commission Panel rejects the relief sought by CEC with respect to conditioning the approval of the expenditure of $12.5 million in F2007 and F2008 to complete the Definition Phase of Revelstoke Unit 5 on BC Hydro providing an evaluation as to what changes can be made to the transfer pricing agreement between BC Hydro and its subsidiary Powerex which will more fairly accrue the benefits of these significant new investments to ratepayers in relation to trade income. The Commission Panel agrees with BC Hydro that the issue raised by CEC arises not from any one project, but rather by the entirety of BC Hydro's system being available from time to time for electricity trade purposes. The Commission Panel also agrees with BC Hydro that the cap is a matter of government policy, and not something to be reviewed by the Commission.

However, the Commission Panel does agree with CEC that the quantification and allocation of incremental trade benefits from new projects must be addressed by BC Hydro in the application of its Project Evaluation Methodology. Given other findings with respect to the importance of considering costs, benefits, risks and other characteristics from the perspective of BC Hydro customers (including water rentals), the Commission Panel notes that it would not be appropriate to simply subtract trade benefits from other costs in ranking new resource acquisitions. As with other social costs, the Commission Panel agrees that trade benefits that accrue to the shareholder may be considered in selecting among projects with similar financial impacts; however, at this time the Commission Panel would not consider it appropriate for ratepayers to pay a premium for projects that provide benefits that accrue to the Province given other determinations in this proceeding. The Commission Panel supports BC Hydro's commitment to include in future facilities applications, to the extent possible, enumeration of the expected benefits for the particular project, and the anticipated allocations of such benefits given BC Hydro's Transfer Pricing Agreement with Powerex and the cap on trade income allocated to ratepayers under the Heritage Contract. However, the Commission Panel also considers this issue should be addressed more generally in future IEP and LTAP applications.

VIGP Cost of Capital Decision

BC Hydro requests that the Commission Panel "revise" the Commission's decision with respect to its VIGP Decision. The Commission Panel observes that the VIGP proceeding differed in a number of respects from the 2006 IEP/LTAP proceeding in that:

- BC Hydro proposed to incorporate a separate subsidiary to own and operate the project;
- there was an issue concerning sunk costs;
- there was a possibility that BC Hydro might have been required to institute a Call for Tenders to see if any more cost-effective projects existed on Vancouver Island; and
- the capital charge proposed by VIEC of $28 million per year using 100 percent debt was the same as that approved by the Commission Panel using 80/20 percent, thus demonstrating that, in the hearing, little turned on the methodology.

The Commission Panel sees no need to revise the VIGP Decision and is content to observe that the finding the Commission made in the VIGP Decision is not relevant to the issue of BC Hydro's general Project Evaluation Methodology given the unique circumstances in the VIGP proceeding.

9.0 2006 LTAP AND SECTION 45(6.1)

In its Reply, BC Hydro sought a number of findings from the Commission Panel, of which six were the subject of a summary determination on March 15, 2007 in Order No. G-29-07, leaving the following matters for the Commission Panel to determine:

- an Order that the LTAP meets the requirements of Section 45(6.1) of the Act;
- that the LTAP plan and CRPs be approved for inclusion in BC Hydro's 2006 NITS update/application;
- endorsement of BC Hydro's future regulatory review process proposal;
- comment on the BC Hydro Project Evaluation Methodology, including revision to the Commission's decision with respect to VIGP;
- endorsement of the specific project evaluation economic measures; and
- comment on the 2006 IEP planning objectives of maximizing reliability, minimizing financial costs of energy production over the 20-year planning horizon and minimizing environmental risk.

The matter of the transmission CRPs is reviewed in Section 7 of this Decision and the Commission Panel's finding is set out therein.

The endorsements and comments sought by BC Hydro have been dealt with by the Commission Panel as follows:

- future regulatory review process in Section 2.5;
- project evaluation methodology and economic measures in Section 8; and
- planning objectives in Section 2.2.

Accordingly, this Section will deal solely with whether BC Hydro's 2006 LTAP meets the requirements of Section 45(6.1) of the Act.

Section 45(6.1) of the Act reads as follows:

> 45 (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission:
>
> (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
>
> (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
>
> (c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.

The Commission's response to Section 45(6.1) is set out in Section 45(6.2) of the Act which reads as follows:

> 45 (6.2) After receipt of a plan filed under subsection (6.1), the commission may
>
> (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in that plan,
>
> (b) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and
>
> (c) determine the manner in which any expenditures referred to in the plan can be recovered in rates.

In December 2003, the Commission established its Guidelines, which state at page 1:

> "On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1 (a), (b) and (c) be prepared in accordance with the Guidelines."

The Commission states that its Guidelines do not mandate a specific outcome to the planning process, nor do they mandate specific investment decisions but provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service (Exhibit A2-21).

BC Hydro submits that in preparing the 2006 IEP, it was guided by regulatory best practices, and the result is consistent with the Commission's Guidelines; that its portfolio analysis is also consistent with the Commission's Guidelines; and that with respect to both EE3, EE4 and EE5 and the 2007 Call, the level of detail contained in the LTAP is consistent with a planning-level document, Policy Action No. 13 of the 2002 Energy Plan and Commission Guideline No. 7 (BC Hydro Argument pp.24, 66 and 77).

No Intervenor challenges this assertion.

Commission Determination

BC Hydro filed its 2006 IEP/LTAP Application on March 29, 2006 and this Decision is being issued some 13 months later, which is a longer period of elapsed time than the Commission has established for itself. The process was lengthened by a number of factors, including BC Hydro's filing of its F07/F08 RRA two months late, and by the two Section 71 proceedings in the year 2006, one of which (LTEPA+) added at least one month to the 2006 IEP/LTAP proceeding. Minor delays were also allowed to provide BC Hydro and Intervenors opportunities to comment on possible impacts of the Province's Throne Speech on these proceedings.

However, the main factor for the length of time was the four rounds of information requests, which meant that the oral phase of the proceedings did not get underway until November 2006. The volume of information requests can, in the Commission Panel's opinion, be ascribed to the fact that this was the first IEP BC Hydro had produced since the 2002 Energy Plan that was capable of meaningful review and that it was necessary for all parties to the proceeding to educate themselves in the matter of BC Hydro's resource planning. The Commission Panel expects that future LTAP proceedings can be dealt with in a shorter timeframe, with only new data (such as the 2007 CPR in the next LTAP) together with significant changes in assumptions or methodology receiving detailed scrutiny.

While the Commission Panel is generally satisfied that BC Hydro complied with the Guidelines, and commends BC Hydro for its efforts in putting the Application together and holding it together during the entire process, it is concerned about several aspects of BC Hydro's analysis. At a high level the Commission Panel has the following observations concerning BC Hydro's 2006 LTAP which it expects BC Hydro to address in its future IEP or LTAP Applications:

1. The Commission Panel finds that BC Hydro should ensure more transparency and explanation of the support provided by the IEP to the LTAP, particularly as related to BC Hydro's objectives and planning criteria. For example, avoidance of gas market exposure risk and replacement of Burrard developed into key objectives for BC Hydro during the proceeding but were not articulated as primary objectives in the IEP and were not supported by the portfolio analysis outcomes. BC Hydro should strive to have the next IEP provide more than "a broad contextual backdrop" for an LTAP.

2. The Commission Panel also expects greater transparency concerning BC Hydro's consideration of operations issues in its planning, and is not convinced that BC Hydro's proposed action plan adequately addresses its operations challenges. For example, the portfolios that meet deterministic planning criteria could also be evaluated and compared on other criteria such as the "spill" risk criterion.

3. In the area of risk analysis, the Commission Panel cannot conclude that BC Hydro objectively assessed risk; rather, it appears to have understated the risks associated with DSM, IPP projects, and transmission while overstating the risk of market exposure. Furthermore, BC Hydro failed to adequately define market exposure and to consider the benefits, costs and risks of reducing market exposure.

4. While the Commission Panel agrees that BC Hydro appropriately engaged its stakeholders, the Commission Panel questions the efficacy of BC Hydro's use of stakeholder input. The Guidelines state that "utility management is responsible for its … resource selection process". The Commission Panel expects BC Hydro to prepare future IEP's using objectives that it has endorsed. Other objectives may be used in dialogue with stakeholders and be the subject of an appendix to the IEP, but should not be the basis for the IEP analysis and main Application. While there may be value in developing attributes to reflect stakeholder objectives, the Commission Panel also concludes that these attributes should not be carried forward into the IEP proceeding unless they have been adopted by BC Hydro for objectives endorsed by BC Hydro.

5. The Commission Panel notes that BC Hydro has not and does not plan to rely on the CE to provide dependable capacity. As a result, a key option was not explicitly considered in the portfolio analysis, namely increased reliance on the CE as a source of capacity for the Lower Mainland. This portfolio, of course, would require additional analysis of transmission issues.

6. The Commission Panel considers BC Hydro's analysis of security of supply wholly inadequate and that its analysis failed to distinguish clearly between questions such as the physical security of supply and price certainty. The analysis further failed to distinguish between supply security and self-sufficiency.

7. With respect to the Burrard issue, the Commission Panel is concerned by BC Hydro's lack of clarity regarding this issue. As noted in Section 3 of this Decision, the Commission Panel does not accept excluding the firm capability of Burrard from available supplies, until a decision to retire the plant has been made by BC Hydro and accepted by the Commission.

In other respects, the Commission Panel finds that BC Hydro has complied with the Guidelines. The Commission Panel does not find the above noted deficiencies determinative with respect to accepting the current LTAP / CRPs, as their effect on near-term actions will be minimal. However, the Commission does expect these deficiencies to be addressed in the next IEP/LTAP filings.

Accordingly, the Commission Panel finds that BC Hydro's 2006 LTAP meets the requirements of Section 45(6.1) of the Act.

10.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	The Commission Panel agrees with BC Hydro that it has an obligation as a public utility to provide reliable, cost-effective electricity supply in an environmentally responsible manner, sufficient to meet customer demand and that this obligation should form the basis of its planning objectives.	26
2.	The Commission Panel accepts BC Hydro's proposal regarding the timing of IEP and LTAP filings in most respects, and agrees that some flexibility is required regarding filing dates to allow it sufficient time to complete the 2007 CPR and the preliminary EE 3, EE4 and EE5 definition work, and to incorporate those studies, as well as evolving government policy, into its next LTAP.	42
3.	The Commission Panel directs BC Hydro to include with its next load forecast a report assessing if there are statistically quantifiable trends associated with the temperature metrics used to forecast peak and energy demands, and an analysis of whether these trends should be extrapolated or otherwise incorporated for use in predicting peak and energy usage in the future. Whether BC Hydro determines it should continue to use temperatures based on historical averages or a statistical trend for forecasting peak and energy demand, the Commission Panel expects BC Hydro to provide a clear and consistent rationale for the historical period it uses for calculating averages, estimating trends, or evaluating variability.	47-48
4.	The Commission Panel accepts BC Hydro's undertaking to provide adjustments to a load forecast within the updated forecast, and in a manner that provides an explanation of the adjustments and reconciliation to the load forecast.	51
5.	Subject to the issues noted above and in Sections 3.2.4 and 6.1.2, the Commission Panel finds that BC Hydro's load forecast has generally been prepared in accordance with the Commission's Guidelines and further accepts that the results of the 20-year forecast are reasonable for the purposes of the 2006 IEP/LTAP. At the time of filing its next annual load forecast, the Commission Panel directs BC Hydro to provide a review of its prospective forecast range as produced by the Monte Carlo simulation, relative to its historical experience.	52

6.	The Commission Panel directs BC Hydro to file a report with the Commission in its next IEP, identifying significant trends in the literature and summarizing the results of its statistical analyses of historical streamflows.	56
7.	The Commission Panel accepts BC Hydro's reliance on 2,500 GW.h/ yr for the purposes of the current LTAP, but considers that BC Hydro's decision to amend its policy to rely on domestic non-firm sources only, rather than on a mix of sources, remains an open issue which it expects BC Hydro to address in its next LTAP and in any approvals of acquisitions for non-firm energy in the 2007 Call.	58
8.	The Commission Panel notes that in different versions of the load/resource balance BC Hydro has included a line item for "additional reserves" but this line item is found in a different location and does nothing to aid understanding of the load/resource balance. The Commission Panel directs BC Hydro to address this apparent anomaly in its next LTAP. Given transmission constraints noted by BC Hydro, the Commission Panel is concerned that BC Hydro is overestimating the available capacity from reserve sharing and the CE. The Commission Panel directs BC Hydro to address this issue in its next LTAP.	61
9.	The Commission Panel expects BC Hydro to consider the issue of the effects of aggregating intermittent resources on dependable capacity within the 2007 Call and in its next IEP. The Commission Panel is concerned that BC Hydro may be overstating the dependable capacity of future intermittent resources and directs it to continue to carry out hydrological and wind studies that may inform its estimates of dependable capacity for existing and future intermittent resources in its next call and IEP.	64
10.	The Commission Panel directs BC Hydro to file a study in the next LTAP that identifies the level of firm transmission capacity available to deliver the CE to British Columbia from the United States.	67
11.	… the Commission Panel rejects BC Hydro's assumption that Burrard will have no contribution to dependable capacity or firm energy beyond F2014.	73
12.	Given uncertainty over the future of Burrard and the availability of the existing non-firm/ market allowance, the Commission Panel finds there is a critical need for new resources based on reliability planning criteria, but that the magnitude of BC Hydro's long-term need for energy and capacity for reliability planning purposes may be somewhat overstated.	80

13.	The Commission Panel accepts the proposal described in Exhibit B-102 that BC Hydro will request BCTC to study the effects of the transmission planning assumptions related to Coastal Regional RMR generation, Interior Region Heritage resource dispatch and the treatment of intermittent resources, and that based on the outcome of these studies, BC Hydro may modify these planning assumptions as part of its NITS application.	113
14.	The Commission Panel encourages BCTC to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis and the NITS application review. The Commission Panel directs BC Hydro to provide a description of these planning assumptions in the next LTAP application. The description of the planning assumptions should address coastal capacity reserve requirements in the determination of coastal RMR capacity, including the dispatch of Burrard.	114
15.	BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that the $1.7 million expenditures required to undertake and complete the Definition phase work of EE3, EE4, and EE5 and the updated CPR are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07. BC Hydro's request for a determination under Section 45(6.2)(b) of the Act that expenditures of $0.8 million for the electricity savings associated with the Greater Vancouver Water District micro-hydro Load Displacement project are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07.	139
16.	The Commission Panel directs BC Hydro to continue to file reports on DSM performance as described in Directive 69 included in Order No. G-96-04 and to file its Semi-Annual Demand Side Management Reports in the same format as the June 2005 Report with the following enhancements: (4) Provide annual and cumulative totals since program inception; (5) Express these values on a per unit basis; and (6) Provide the benefit to cost ratios for the three DSM tests. The Commission Panel also directs BC Hydro to continue to employ the three DSM tests in a manner consistent with Directive 70 included in Order No. G-96-04.	145-146
17.	… the Commission Panel directs BC Hydro to file a report containing, among other things, a financial forecast of BC Hydro's rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. Input assumptions should be summarized in a concise, but comprehensive manner.	154

18.	BC Hydro’s request for a determination under Section 45(6.2)(b) of the Act that expenditures of $2,875,000 required to undertake and complete the identification phase work for the 2007 Call are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07.	164
19.	BC Hydro’s request for a determination under Section 45(6.2)(b) of the Act that expenditures of $520,000 required to undertake and complete the identification phase work for the 2009 Call are in the interests of persons within B.C. who receive, or may receive, service from BC Hydro was approved in Order No. G-29-07. The Commission Panel notes that BC Hydro is not requesting approval of a Call volume at this time and the Commission Panel will not comment on the proposed volume of the 2009 Call at this time.	165
20.	The Commission Panel concludes that BC Hydro’s options for acquiring adequate capacity in the near-term are limited and that, based on BC Hydro’s preliminary analysis, Revelstoke Unit 5 may be a cost-effective capacity addition. BC Hydro’s request for a determination under Section 45(6.2)(b) of the Act that expenditures of $12.5 million in F2007 and F2008 required to complete the Definition phase of Revelstoke Unit 5 are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro was approved in Order No. G-29-07.	168
21.	The Commission Panel directs BC Hydro to include the Waneta Expansion Project in its next ROR. The Commission Panel directs BC Hydro to include a pumped storage hydro project on the Jordan River in its next ROR.	168
22.	BC Hydro’s request for a determination under Section 45(6.2)(b) of the Act that expenditures of $1.0 million in F2007 and $2.0 million in F2008 required to complete the Identification and Definition phase work for the next Revelstoke or Mica Unit are in the interests of persons within B.C. who receive, or who may receive, service from BC Hydro was approved in Order No. G-29-07.	170
23.	The Commission Panel finds that the use of the high load forecast is an appropriate contingency to incorporate in the CRPs, but finds a further assumption of reduced DSM response to be redundant unless BC Hydro can show in a future application a difference in the effect on the CRPs between an increase in load forecast as compared to a reduction in DSM response.	179-180

24.	The Commission Panel accepts the use of the LTAP Base Case and CRPs described in Exhibit B-1E and Exhibit B-55 for use in BC Hydro's next NITS update/application. With reference to the concerns noted regarding the composition of the LTAP Base Case and CRPs, the Commission Panel invites BC Hydro, at its earliest opportunity and preferably prior to the next NITS application, to submit for approval updated LTAP Base Case and CRPs that better reflect BC Hydro's expectations of future resource additions. In approving the LTAP Base Case and CRPs for the purposes of inclusion in BC Hydro's NITS Application, as noted in Section 6 of this Decision the Commission Panel is not endorsing targets for specific resources or acquisitions.	181-182
25.	The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro.	200-201
26.	Based on forecasts of capital expenditures and debt levels prepared by BC Hydro in this proceeding, the Commission Panel accepts that for the foreseeable future incremental capital projects will effectively be financed with 100 percent debt. BC Hydro borrows at rates that reflect the Provincial Government's credit rating and current nominal interest rate on 20 to 30-year debt for BC Hydro, and thus its ratepayers, is approximately 4.60 percent per annum. The Commission Panel concludes this is the appropriate discount rate for BC Hydro to use to evaluate resource options under the current assumption of 100 percent debt financing	202-203
27.	Accordingly, the Commission Panel finds no justification for the use of different discount rates for the economic analysis and the ratepayer impact analysis. The Commission Panel considers the issue of risk to be dealt with adequately through the sensitivity and scenario analysis. However, the Commission Panel does continue to see value in sensitivity analyses around a single discount rate.	204
28.	The Commission Panel confirms Directive 60 from the F05/06 RRA Decision, which accepts three DSM cost/benefits screening tests as appropriate – Utility Cost Test, All Ratepayers Test and Non-Participant Test.	206
29.	Accordingly, the Commission Panel finds that BC Hydro's 2006 LTAP meets the requirements of Section 45 (6.1) of the Act.	214

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of May 2007.

Original signed by:

ROBERT H. HOBBS
PANEL CHAIR

Original signed by:

NADINE F. NICHOLLS
COMMISSIONER

Original signed by:

A.J. (TONY) PULLMAN
COMMISSIONER

BRITISH COLUMBIA UTILITIES COMMISSION

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Applications by British Columbia Hydro and Power Authority ("BC Hydro")
for the Review of the 2006 Integrated Electricity Plan ("2006 IEP")
and the Approval of the 2006 Long-Term Acquisition Plan ("LTAP")

BEFORE: R.H. Hobbs, Chair
N.F. Nicholls, Commissioner
A.J. Pullman, Commissioner

March 15, 2007

O R D E R

WHEREAS:

A. By Commission Order No. G-103-05 dated October 5, 2005, the Commission approved a Negotiated Settlement in the Resource Expenditure Acquisition Plan ("REAP") proceeding. In the REAP Negotiated Settlement, BC Hydro committed to seek, pursuant to Section 45 (6.2) of the Utilities Commission Act (the "Act", "UCA"), regulatory approval of the LTAP, to be included with the 2006 IEP; and

B. On March 29, 2006, BC Hydro filed, pursuant to Section 45 (6.1) of the Act, the 2006 IEP and the LTAP with the Commission for review; and

C. On August 31, 2006, BC Hydro filed an amended LTAP (Exhibit B1-E) which included new information affecting the LTAP load-resource balance and the Orders sought. The amended LTAP forms Chapter 8 of the 2006 IEP; and

D. BC Hydro seeks an Order which: (i) states that the 2006 LTAP meets the requirements of Section 45 (6.1) of the UCA; (ii) makes specific determinations under subsection 45 (6.2)(b) of the UCA with respect to certain planned expenditures; and (iii) approves the transmission LTAP plan and contingency plans for inclusion in the Utility's Network Integrated Transmission Service application; and

E. The 2006 IEP is a long-term plan that describes how BC Hydro could meet customers' electricity needs over a 20-year planning horizon and the resource options available to meet those needs under a variety of assumptions and risks; and

F. The LTAP is an action plan that is supported by the 2006 IEP. It itemizes the actions BC Hydro intends to take in the next ten years to meet customers' electricity needs as part of BC Hydro's overall planning and resource acquisition process; and

G. Opening Oral Submissions took place on November 14, 2006 and the submissions on the BC Hydro Consolidation of the Hearing Issues List took place on November 16, 2006; and

H. The Consolidated Hearing Issues List was issued on November 20, 2006 (Exhibit A-33) and the Public Hearing commenced on November 22, 2006 in Vancouver; and

I. Subject to the filing of certain outstanding information requests, the evidentiary phase of the proceeding closed on January 12, 2007. The Chair established a schedule for final argument which provided that BC Hydro file its Final Argument on February 2, 2007, the Intervenors on February 16, 2007 and BC Hydro file its Reply Argument on February 23 2007. An Oral Phase of Argument, if required, was scheduled for March 14, 2007; and

J. On February 13, 2007, the Provincial Government delivered the Throne Speech which contained pronouncements relating to a new energy policy. In order to allow participants to comment on matters arising from the Throne Speech, by letter of the same date (Exhibit A-42), the Commission Panel proposed certain amendments to the schedule for final argument. The proposal contemplated an extension in the date for filing of Intervenor Final Argument to February 19, 2007 with Reply Argument by BC Hydro on February 26, 2007. All participants were invited to comment on this proposal by February 14, 2007; and

K. Following the receipt of responses from participants, by letter dated February 13, 2007 (Exhibit A-44), the Commission accepted that the Throne Speech as Exhibit A2-26. The date for filing of Intervenor Final Argument was extended to February 23, 2007, and the date for the filing of BC Hydro Reply Argument to March 5, 2007; and

L. On February 27, 2007 the Provincial Government released its update to the 2002 Energy Plan. By letter of the same date (Exhibit A-45), the Commission Panel invited comments from all participants on the relevance and procedural changes that would arise from the 2007 Energy Plan or (“Energy Plan II”). The Commission Panel proposed that Intervenors address any matters arising from Energy Plan II in supplemental submissions that would be due on March 2, 2007 and that BC Hydro identify and incorporate changes to the Application in its Final Argument if any such changes arise from Energy Plan II. All participants were invited to comment on this request by February 28, 2007; and

M. By letter dated February 28, 2007 (Exhibit B-151), BC Hydro submitted that the process and timelines proposed by the BCUC to address the implications of Energy Plan II on the 2006 IEP and LTAP did not realistically afford either BC Hydro or Intervenors the opportunity to address Energy Plan II matters. BC Hydro requested an extension to March 7, 2007 for the filing of its Reply Argument and to confirm its proposal to file the Revelstoke Unit 5 Certificate of Public Necessity and Convenience (“CPCN”) in advance of receipt of the 2006 IEP/LTAP decision. BC Hydro also submitted that the March 14, 2007 date for Oral Argument should proceed; and

N. By Letter No. L-12-07 dated February 28, 2007 (Exhibit A-46) the Commission Panel determined that Energy Plan II should not form part of the 2006 IEP/LTAP proceeding or record, and extended the date for the filing of BC Hydro's Reply Argument to March 7, 2007. The Commission Panel did not comment on the BC Hydro's proposal to file a CPCN for Revelstoke Unit 5 and deferred its determination as to whether to proceed with the Oral Phase of Argument until the receipt and perusal of BC Hydro's Reply Argument; and

O. By letter dated March 8, 2007 (Exhibit A-47), the Commission Panel determined that an Oral Phase of Argument was not required. The Commission Panel also decided that participants who wished to make further comments on matters relating to the Throne Speech addressed by BC Hydro in its Reply Argument could do so on or before March 12, 2007 and that BC Hydro would have the opportunity to respond on or before March 13, 2007; and

P. The Written Argument phase of the proceeding was completed upon receipt of a letter from BC Hydro dated March 13, 2007 (Exhibit B-152). The letter objected to two letters, both dated March 12, 2007, on the basis that they addressed subject matters that clearly did not relate to the Throne Speech. The letters were from the Sierra Club of Canada *et al.* (Exhibit C25-25) and Vanport Sterilizers Inc. (Exhibit C39-5); and

Q. The Commission Panel considers that there is enough information on the record to allow the Panel to make the specific determinations that BC Hydro is seeking, as set out on page 8 of BC Hydro's Final Argument prior to a Final Order on the remaining orders and comments sought in the Applications. Accordingly, the Commission Panel determines that the specific determinations set out on page 8 of the BC Hydro Final Argument should be accepted pursuant to subsection 45(6.2)(b) of the Act. The reasons for decision for the determination will be included in the Reasons for Decision with respect to the remaining orders and comments sought by BC Hydro, which Reasons will be issued concurrently with the Final Order for the 2006 LTAP. Those Reasons for Decision and the Final Order will be issued in due course.

…/4

NOW THEREFORE pursuant to subsection 45 (6.2)(b) of the Act the Commission orders as follows:

The following expenditures are determined to be in the interests of persons within British Columbia who receive, or who may receive, service from BC Hydro:

(i) $1,700,000 required to undertake and complete the Definition phase work of Energy Efficiency (EE) 3, 4 and 5, including completion of an updated Conservation Potential Review (CPR);

(ii) $800,000 for the electricity savings associated with the Greater Vancouver Water District micro-hydro Load Displacement (LD) 2 project;

(iii) $2,875,000 to undertake and complete the Identification, Definition and Implementation phase work for the 2007 Call;

(iv) $520,000 required to undertake and complete the Identification phase work for the 2009 Call;

(v) A total of $12,500,000 required to complete the Definition phase of Revelstoke Unit 5 in the years F2007 and F2008; and

(vi) A total of $3,000,000, $1,000,000 in F2007 and $2,000,000 in F2008, required to complete the Identification and Definition phase work for the next Revelstoke or Mica unit.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of March 2007

BY ORDER

Robert H. Hobbs
Chair

ACRONYMS AND ABBREVIATIONS

Application	The 2006 IEP and LTAP filing
Alcan	Alcan Inc.
BC Hydro	British Columbia Hydro and Power Authority
BCUC	British Columbia Utilities Commission
BCOAPO	British Columbia Old Age Pensioners Organization *et al.*
BCTC	British Columbia Transmission Corporation
BTGS, Burrard	Burrard Thermal Generating Station
CE	Canadian Entitlement
CEC	Commercial Energy Consumers of BC
CEMS	Continuous Emission Monitoring System
CFL	Compact Florescent Light program
CFT	Call For Tender
CIAC	Contributions In Aid of Construction
COD	Commercial Operation Date
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review
CRP	Contingency Resource Plan
CPC	Columbia Power Corporation
DGC	Dependable Generating Capacity
DSB	Downstream Benefits
DSM	Demand Side Management
DoK	District of Kitimat
EE	Energy Efficiency programs
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Energy Purchase Agreement
ERCOT	Electric Reliability Council of Texas

ESC	Energy Supply Contract
ESVI	Energy Solutions for Vancouver Island Society
Energy Plan II or 2007 Energy Plan	Provincial Government's "The BC Energy Plan: A Vision for Clean Energy Leadership" issued on February 27, 2007
2002 Energy Plan	Provincial Government's "Energy for Our Future: A Plan for BC" issued on November 25, 2002
F07/F08 RRA	F2007/F2008 Revenue Requirements Application
GDP	Gross Domestic Product
GHG	Green House Gas
GWh, GW.h	Gigawatt hour
Guidelines	BCUC Resource Planning Guidelines issued in December 2003
GVRD	Greater Vancouver Regional District
HC	Heritage Special Directive to BC Hydro
HDD	Heating Degree Day
HLH	High Load Hour
ICP	p. 116, need long form from author
IEP	Integrated Electricity Plan
IPPBC	Independent Power Producers association of BC
IR	Information Request
IRP	Integrated Resource Plan
ILM	Interior to Lower Mainland transmission
JIESC	Joint Industry Electricity Steering Committee
kW	kilowatt
LD	Load Displacement program

LLH	Light Load Hour
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LTAP	Long Term Acquisition Plan
LTEPA	Long Term Electricity Purchase Agreement
LTEPA+	Amended and Restated Long Term Electricity Purchase Agreement
MCR	Maximum Continuous Rating
MW	Megawatt
MWh, MW.h	Megawatt hour
NEB	National Energy Board
NIA	Non-Integrated Areas
NITS	Network Integration Transmission Services
NPV	Net Present Value
NRCan	Natural Resources Canada
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
NWPP	Northwest Power Pool
NOx	Nitrogen Oxide
PIEPC	Provincial Integrated Electricity Plan Committee
PSP	Power Smart Partner
PV	Present Value
REAP	Resource Expenditure and Acquisition Plan
REEPS	Residential End-Use Energy Planning Systems
RIM	Ratepayers Impact Measurement
ROE	Return on Common Equity
ROI	Return on Investment
ROR	Resource Options Report
RMR	Reliability-Must-Run
RRA	Revenue Requirements Application

SCCBC	Sierra Club of Canada, British Columbia Chapter et al.
StatsCan	Statistics Canada
SCR	Selective Catalytic Reduction
TGP	Total Gas Pressure
TRC	Total Resource Cost
ToR	Terms of Reference
Throne Speech	Speech from the Throne at the Opening of the Third Session of the 38th Parliament of the Provincial Government on February 13, 2007
UCA, the Act	Utilities Commission Act
UCC	Unit Capacity Cost
UEC	Unit Energy Cost
UT	Utility Test
Vanport	Vanport Sterilizers Inc.
VIGP	Vancouver Island Generating Plant project
VITR	Vancouver Island Transmission Reinforcement project
WACC	Weighted Average Capital Cost

APPEARANCES

G.A. FULTON, Q.C. P. MILLER	Commission Counsel
C. GODSOE K. HUGHES K. BERGNER	British Columbia Hydro and Power Authority
P. FELDBERG M. GHIKAS	British Columbia Transmission Corporation
F. WEISBERG	Columbia Power Corporation
D. PERTTULA	Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. Terasen Gas (Squamish) Inc.
R.B. WALLACE I. CHANG	Joint Industry Electricity Steering Committee
D. NEWLANDS	Elk Valley Coal Corporation
K. DUKE	Alcan Primary Metal Group
D. BENNETT	FortisBC Inc.
S. BARRACLOUGH	EPCOR Utilities Inc.
D. AUSTIN	Independent Power Producers of British Columbia
C. WEAFER	Commercial Energy Consumers' Association of British Columbia
R. PERCIVAL	Dokie Wind Energies Inc.
J. JOHNSON	Cloudworks Energy Inc.
S. EBNET	Green Island Energy Ltd.
R. CARLE	City of New Westminster
P. COCHRANE	Willis Energy Services Limited

APPEARANCES
(cont'd)

J. HUNTER, Q.C. M. OULTON	District of Kitimat
J. QUAIL L. WORTH	B.C. Old Age Pensioners' Organization, the Active Support Against Poverty, B.C. Coalition of People with Disabilities, Council of Seniors' Organizations of B.C., End Legislated Poverty, Federated Anti-Poverty Groups of B.C., and the Tenants' Rights Action Coalition
W. ANDREWS T. HACKNEY	Sierra Club Of Canada, B.C. Chapter; B.C. Sustainable Energy Association; and Peace Valley Environmental Association
J. THAYER	Lone Prairie Community Association
L. BERTSCH	Energy Solutions for Vancouver Island
W. PEARCE, Q.C.	World Federalists of Canada
R. TENNANT	Van Port Sterilizers Incorporated
A. WAIT	Himself

LIST OF WITNESSES

ROBERT ELTON	British Columbia Hydro and Power Authority Panel 1A
DAWN FARRELL BEVERLEY VAN RUYVEN	Panel 1B
GRAEME SIMPSON CAM MATHESON KEN TIEDEMANN JOHN DUFFY	Panel 2
RENATA KURSCHNER MICHAEL STANDBROOK DAVID INCE RICHARD LAUCKHARD (VICE PRESIDENT XXX)	Panel 3
KRISTIN HANLON TIM LESIUK RICHARD ROSENZWGIG (NOT A HYDRO EMPLOYEE) DOUGLAS RUSSELL (NOT A HYDRO EMPLOYEE)	Panel 4
CAM MATHESON RANDY REIMANN HEATHER MATTHEWS KIRSTIN HANLON	Panel 5
ALISTER COWAN MICHAEL STANDBROOK RANDY REIMANN STEPHEN HOBSON MARK GIDRIDGE	Panel 6
BEVERLY VANRUYVEN RANDY REIMANN DAVID KUSNIERCZYK STEPHEN HOBSON STEVEN ECKERT	Panel 7
PAUL CHOUDHRY CAMERON LUSZTIG PHILIP PARK	British Columbia Transmission Corporation

LIST OF WITNESSES
(cont'd)

DR. MARVIN SHAFFER	Columbia Power Corporation
HARVIE CAMPBELL STEVE DAVIS JAMES WEIMER	Independent Power Producers Association of British Columbia
JOHN PLUNKETT ROBERT FAGAN	Sierra Club of Canada British Columbia, BC Sustainable Energy Association, and the Peace Valley Environmental Association (collectively "SCCBC et al.)

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
2006 Integrated Electricity Plan and Long-Term Acquisition Plan

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated March 23, 2006 issuing Order No. G-32-06 regarding Interim Rates
A-2	Letter dated April 4, 2006 issuing Order No. G-37-06 and Notice of Procedural Conference
A-3	Letter dated April 21, 2006 issuing Information Request No. 1 to BC Hydro
A-4	Letter dated May 10, 2006 confirming date for Procedural Conference and filing proposed Regulatory Agenda
A-5	Letter dated May 25, 2006 and Order No. G-59-06 issuing an amended Regulatory Timetable
A-6	Letter No. L-21-06 dated May 25, 2006 issuing Reasons for Order No. G-59-06 regarding the Reconsideration of Order No. G-32-06
A-7	Letter dated June 2, 2006 issuing Information Request No. 2 to BC Hydro
A-8	Letter dated June 8, 2006 responding to BC Hydro's request for extension for filing responses to Information Requests (Exhibit B-8)
A-9	Letter dated July 10, 2006 issuing Information Request No. 3 to BC Hydro
A-10	Letter dated July 14, 2006 responding to BC Hydro's request for an extension to the deadline for responses to Commission's Information Request No. 1 on F07/08RRA and Intervenors' Information Request No. 1 on F07/08RRA, and Commission's Information Request No. 3 and Intervenors' Information No. 2 on Evidence on Project Evaluation (Exhibit B-13)
A-11	Letter dated July 14, 2006 requesting comments from participants regarding BC Hydro's request for the Commission to broadcast the audio portion of the upcoming public hearing over the Internet

Exhibit No.	Description
A-12	Letter dated July 24, 2006 notification to proceed with Audio On-Line Broadcasting service
A-13	Letter dated July 26, 2006 issuing Agenda for the Second Procedural Conference and draft alternative Regulatory Timetables
A-14	**SUBMISSION AT HEARING** - Revised Agenda for August 1, 2006
A-15	Letter dated August 3, 2006 and Order No. G-96-06 establishing the Regulatory Timetable
A-16	Letter dated August 14, 2006 issuing Information Request No. 1 to Terasen Gas Inc.
A-17	Letter dated September 8, 2006 issuing Information Request No. 4 to BC Hydro
A-18	Letter dated September 22, 2006 to SCCBC et al regarding Exhibit C25-6
A-19	Letter dated September 22, 2006 to SCCBC et al regarding Exhibits No. C25-6 and C25-8
A-20	Letter dated October 10, 2006 request to Intervenors to submit their position regarding the request for the F2006 Call Report to be admitted as evidence (Exhibit C25-9)
A-21	Information Request No. 1 dated October 13, 2006 to Sierra Club of Canada BC Chapter's (SCCBC)
A-22	Information Request No. 1 dated October 13, 2006 to World Federalists of Canada
A-23	Information Request No. 1 dated October 13, 2006 to Independent Power Producers Association of BC
A-24	Information Request No. 1 dated October 13, 2006 to Columbia Power Corporation
A-25	Information Request No. 1 dated October 13, 2006 to British Columbia Transmission Corporation
A-26	Information Request No. 1 dated October 13, 2006 to the District of Kitimat
A-27	Letter dated October 13, 2006 filing response to the request for the F2006 Call Report to be admitted as evidence
A-28	Letter dated October 31, 2006 issuing Notice confirming the date, time and location of the Third Procedural Conference

Exhibit No.	**Description**
A-29	Letter dated November 6, 2006 issuing the Agenda for the Third Procedural Conference
A-30	Letter dated November 9, 2006 issuing the Commission Issues List
A-31	Letter dated November 9, 2006 regarding guideline on consultation with witnesses under cross-examination
A-32	Letter dated November 17, 2006 responding to Richard Tennant of Vanport Sterilizers Inc request for leave to file Evidence (Exhibit C39-2)
A-33	Letter dated November 20, 2006 issuing the Consolidated Issues List
A-34	Letter dated November 20, 2006 responding to World Federalists' request for leave to file evidence (Exhibit C24-7).
A-35	Letter dated November 21, 2006 issuing an amendment to letter (Exhibit A-34)
A-36	**SUBMITTED AT HEARING –** Excerpt from the VITR Decision and other documentation relating to the VITR Proceeding
A-37	**SUBMITTED AT HEARING –** BC Hydro PowerSmart Summary of Demand Side Management Evaluation Reports for Fiscal Year 2004/05 dated July 2005
A-38	**SUBMITTED AT HEARING –** BC Hydro PowerSmart Semi-Annual Report on Demand Side Management Activities dated February 2006
A-39	**SUBMITTED AT HEARING –** BCUC Information Request 1.141.1, Attachment 1, PA Consulting Group – BC Hydro Review of PowerSmart Evaluation Process Final Report (Draft) dated May 27, 2005
A-40	Letter dated January 18, 2007, to Ludo Bertsch denying new evidence submitted by email on January 17, 2007
A-41	Letter dated February 1, 2007, denying new evidence submitted by SCCBC (Exhibit C25-22)
A-42	Letter dated February 13, 2007 inviting comments on matters arising from the Throne Speech
A-43	Letter dated February 14, 2007 follow up to Exhibit A-42 letter
A-44	Letter dated February 15, 2007 setting New Schedule arising from Throne Speech
A-45	Letter dated February 27, 2007 requesting comments from BC Hydro and Intervenors on the Provincial Government's Energy Plan

Exhibit No.	Description
A-46	Letter dated February 28, 2007 responding to submissions regarding the BC Energy Plan
A-47	Letter dated March 8, 2007, issuing cancellation of the proposed Oral Phase of Argument on the Throne Speech of February 13, 2007 (Exhibit A-46) and issuing request for comments

COMMISSION COUNSEL DOCUMENTS

A2-1	Letter dated May 18, 2006 responding to Intervenors' request for reconsideration and filing copies of the Commission's past decisions regarding Interim Rates
A2-2	Submitted at Pre-Hearing Conference – Heritage Special Direction Order HC2 to the BC Utilities Commission
A2-3	Letter dated November 6, 2006 providing procedural information to participants
A2-4	Email dated November 8, 2006 filing comments and reference copy of the Enbridge Gas Distribution Inc. v. Ontario Energy Board, 2006 CanLII 10734 (ON. C.A.)
A2-5	**SUBMITTED AT HEARING –** Schedule B from the British Columbia Hydro and Power Authority Standards of Conduct
A2-6	**SUBMITTED AT HEARING –** Page 20 of BCTC's South Interior Cut-Plane Reinforcement Justification Report
A2-7	**SUBMITTED AT HEARING –** Commission Information Request No. 2.397.0 dated August 17, 2006
A2-8	**SUBMITTED AT HEARING –** Extract from Revenue Requirement Application 2004-05 and 2005-06 … Volume 2
A2-9	**SUBMITTED AT HEARING –** Extract from Sampson Research … 2004 Market Effects of BC Hydro's Compact Fluorescent Light Program, Final Report – May 12, 2005
A2-10	**SUBMITTED AT HEARING –** Extract from Samson Research … Direct and Market Effects of BC Hydro's 2005-06 Residential CFL Program, Final Report… June 15, 2006
A2-11	**SUBMITTED AT HEARING –** Extract from BC Hydro PowerSmart Report on the Demand-Side Management Activities for the Year Ending March 31, 2006, July 2006

Exhibit No.	**Description**
A2-12	**SUBMITTED AT HEARING –** Extract from Commission Information Requests 2.328.2, 1.164.1 and 2.367.2
A2-13	**SUBMITTED AT HEARING –** Copy of Order of the Lieutenant Governor in Council, No. 503, Dated July 13, 2006
A2-14	**SUBMITTED AT HEARING –** Extract from MEMPR Energy Savings Plan and City of Vancouver Energy Savings Plan
A2-14A	**SUBMITTED AT HEARING –** Two-Page Extract from Energy Savings Plan Website
A2-15	**SUBMITTED AT HEARING –** Excerpts from Appendix A to Order No. G-143-96 and Commission Information Request No. 4.451.1 dated September 8, 2006
A2-16	**SUBMITTED AT HEARING –** Article by Mr. Tiedemann entitled “Impact of Energy Conservation on Electricity Sales”
A2-17	**SUBMITTED AT HEARING –** Commission Information Request No. 2.399.0, dated August 17, 2006
A2-18	**SUBMITTED AT HEARING –** Letter dated February 23, 2006 from National Energy Board to Teck Cominco Metals Ltd., with attached Excerpts from NEB Export Summary Report
A2-19	**SUBMITTED AT HEARING –** Extract from “BCUC Vancouver Island Gas Project Decision dated September 8, 2003
A2-20	**SUBMITTED AT HEARING –** Group of Four Tables
A2-21	**SUBMITTED AT HEARING –** Commission Resource Planning Guidelines, Issued December 2003
A2-22	**SUBMITTED AT HEARING –** Commission Information Request 1.30.2 from BC Hydro F07/08 Revenue Requirements Application
A2-23	**SUBMITTED AT HEARING –** Commission Information Request 2.17.1 from BC Hydro 2006 IEP & LTAP Application, and attached Excerpt from Attachment A
A2-24	**SUBMITTED AT HEARING –** Exhibit B-17-3, Spreadsheet on CD for Commission 4.448.1, sheet labelled “Energy Benefit Scenarios”
A2-25	**SUBMITTED AT HEARING –** Excerpt from “BCTC South Interior Cut-Plane Reinforcement Justification Report … October 2006”

Exhibit No.	Description
A2-26	Copy of the Speech from the Throne, at the Opening of the Third Session, Thirty-Eighth Parliament, Province of British Columbia, dated February 13, 2007

BC HYDRO DOCUMENTS

B-1A	Letter dated March 29, 2006 filing the 2006 Integrated Electricity Plan (IEP) and Long-Term Acquisition Plan (LTAP)
B-1B	Appendices A to F of the 2006 Integrated Electricity Plan (IEP) and Long-Term Acquisition Plan (LTAP)
B-1C	Appendices G to L of the 2006 Integrated Electricity Plan (IEP) and Long-Term Acquisition Plan (LTAP)
B1-D	**CONFIDENTIAL –** Letter dated August 31, 2006 filing amended L TAP Chapter 8 of the 2006 IEP Application, including new information affecting the LTAP load-resource balance
B1-E	Letter dated August 31, 2006 filing redacted amended LTAP Chapter 8 of the 2006 IEP Application, including new information affecting the LTAP load-resource balance
B1-F	Letter dated October 4, 2006 filing amendments to the August 31, 2006 version of the LTAP **Updated October 16, 2006**
B-2	Letter dated March 30, 2006 filing “Challenges & Choices: Planning for a secure electricity future” booklet
B-3	Letter dated April 19, 2006 filing Errata regarding the 2006 Integrated Electricity Plan Application (IEP) with details to be filed in the F2007/F2008 Revenue Requirement Application
B-4	Letter dated May 1, 2006 filing letter regarding the Procedural Conference and date for the Commission’s and Intervenors’ Information Requests
B-5	Letter dated May 9, 2006 to Commission responding to requests to adjourn the Procedural Conference, filing of Information Requests and submission of reconsideration of Order G-32-06
B-6-1	Letter dated May 11, 2006 to Commission filing Information Request No. 1 – Part 1 – IR 1.001.01 to 1.049.01 (Starting at page 64)

Exhibit No.	**Description**
B-6-2	Letter dated May 11, 2006 to Commission filing Information Request No. 1 - Part 2 – IR 1.050.01 to 1.079.02
B-6-3	Letter dated May 11, 2006 to Commission filing Information Request No. 1 - Part 3 – IR 1.080.01 to 1.183.02
B-6-4	Letter dated May 11, 2006 to Commission filing Information Request No. 1 – Part 4 – IR 1.183.03 to 1.288.02
B-6-5	**CONFIDENTIAL –** May 11, 2006 letter and Confidential Response to Commission Information Request No. 1 – IR 168.0
B-6-6	Letter dated May 18, 2006 to Commission filing the outstanding Information Request No. 1 – IR 1.11.1 to 1.274.5
B-6-7	Letter dated November 20, 2006 filing revision to response to Commission Information Request 1.22.1
B-7	Letter dated May 29, 2006 filing Errata for the Rate Impact and Resource Options Report
B-8	Letter dated June 7, 2006 to Commission requesting extension on filing date for Responses Information Requests (Order No. G-59-06)
B-9	Letter dated June 29, 2006 filing Errata, Revision 3, regarding the 2006 Integrated Electricity Plan Application (IEP)
B-10	Letter dated June 30, 2006 filing responses to Information Requests to Commission No. 2 and Intervenor No. 1
B-10-1	Letter dated July 6, 2006 filing responses to outstanding Information Requests to Commission No. 2 and Intervenor No. 1
B-10-2	Letter dated July 21, 2006 filing supplemental responses to Columbia Power Corporation’s specific Information Requests No., 1.2.1 and1.2.6, and referencing Information Requests 1.1.9, 1.2.4, 1.6.1 and 1.6.4
B-10-3	Letter dated September 12, 2006 filing supplement responses and comments to Sierra Club of Canada’s (BC Chapter) Information Request (Exhibit C25-6)
B-11	Letter dated June 30, 2006 filing BC Hydro's Evidence on Project Evaluation
B-12	Letter dated July 13, 2006 filing request to Commission for use of audio online broadcasting service for the upcoming hearing

Exhibit No.	**Description**
B-13	Letter dated July 13, 2006 filing request to Commission for an extension on deadline for responses to Commission's Information Request No. 1 on F07/08RRA and Intervenors' Information Request No. 1 on F07/08RRA, and Commission's Information Request No. 3 and Intervenors' Information No. 2 on Evidence on Project Evaluation
B-14	Letter dated July 28, 2006 filing response and comments to Commission's Draft Agenda for the Second Procedural Conference (Exhibit A-13)
B-15	**SUBMISSION AT HEARING** - Filing proposed Regulatory Timetable
B-16	Letter dated August 3, 2006, filing responses to Project Evaluation information requests to Commission (IR-3) and Intervenors
B17-1	Letter dated September 29, 2006, filing responses to Commission's Information Request No. 4 and Intervenors' Information Request No. 3
B17-2	Partial response to B17-1, dated September 29, 2006 filing response to British Columbia Old Age Pensioners Organization's (BCOAPO) Information Request No. 3
B17-3	Partial response to B17-1, dated September 29, 2006 filing response to the Commission's Information Request No. 4
B17-4	**CONFIDENTIAL** - Partial response to B17-1, dated September 29, 2006 filing response to the Commission's Information Request No. 4.444.1
B17-5	Partial response to B17-1, dated September 29, 2006 filing response to Columbia Power Corporation's (CPC) Information Request No. 3
B17-6	Partial response to B17-1, dated September 29, 2006 filing response to Commercial Energy Consumers Association of BC's (CECBC) Information Request No. 3
B17-7	Partial response to B17-1, dated September 29, 2006 filing response to the Independent Power Producers of BC (IPPBC) Information Request No. 3
B17-8	Partial response to B17-1, dated September 29, 2006 filing response to the District of Kitimat's Information Request No. 3
B17-9	Partial response to B17-1, dated September 29, 2006 filing response to the Sierra Club of Canada BC Chapter's (SCCBC) Information Request No. 3
B17-10	Letter dated October 31, 2006 filing supplemental response to the Commission Information Request No. 4.451.1 regarding Reference Price

Exhibit No.	Description
B-18	Letter dated October 6, 2006 filing response to Sierra Club of Canada BC Chapter's (SCCBC) request for report as Evidence (Exhibit 25-9)
B-19	Letter dated October 13, 2006 filing Information Request No. 1 to BCTC's Evidence (Exhibit C7-7)
B-20	Letter dated October 13, 2006 filing Information Request No. 1 to Sierra Club of Canada (BC Chapter)'s Evidence (Exhibit C25-12)
B-21	Letter dated October 13, 2006 filing Information Request No. 1 to World Federalists of Canada's Evidence (Exhibit C24-3)
B-22	Letter dated October 17, 2006 filing the Report on the F2006 Open Call for Tender Process
B-23	Letter dated October 19, 2006 filing Information Request No. 1 to SCCBC et al (Exhibit C25-11)
B-24	Letter dated November 3, 2006 filing Agenda for Third Procedural Conference
B-25	Letter dated November 6, 2006 filing Direct Evidence Testimony
B-26	Letter dated November 6, 2006 filing Rebuttal Testimony of Stephen Hobson, Randy Reimann and David Kusnierczyk
	EVIDENCE NOT PART OF RECORD - PLEASE SEE TRANSCRIPT VOLUME 24, PAGE 3879
B-27	Letter dated November 7, 2006 filing submission regarding confidentiality of the Amended and Restated Long-Term Electricity Purchase Agreement (LTEPA) and LTEPA Amending Agreement
B-28	Document entitled "2006 IEP/LTAP ALCAN – Related Materials" including a copy of the Replacement Electricity Supply Agreement dated August 5, 1997 between the Province and Alcan Aluminium Limited
B-29	Letter dated November 9, 2006, enclosing Long-term Electricity Purchase Agreement Amending Agreement dated October 27, 2006, between BC Hydro and Alcan Inc. and Amended and Restated LTEPA between BC Hydro and Alcan
B-30	Letter dated November 9, 2006 re: Section 71 Filing of Agreement between Alcan Inc. and BC Hydro, advising on BC Hydro responses to BCUC IR No.1
B-31	Letter dated November 10, 2006 filing a Master IR Allocation for BC Hydro's Direct Testimony panels.

Exhibit No.	Description
B-31A	**SUBMITTED AT HEARING** – Revised Master Information Request Allocation List
B-32	**SUBMITTED AT HEARING –** BC Hydro Opening Statement
B-33	Letter dated November 15, 2006 response to Commission Chair's request at the Opening Oral Submissions, filing transcript references from BC Hydro's F2007-2008 Revenue Requirements Application
B-34	**SUBMITTED AT HEARING –** Consolidated Hearing Issues List
B-34A	**SUBMITTED AT HEARING** – BCUC Issues List for the IEP/LTAP Proceeding
B-35	**SUBMITTED AT HEARING –** Exhibit A-11 of the BC Hydro 2005 REAP proceeding
B-36	Letter dated November 20, 2006 filing Opening Statement of Mr. Bob Elton
B-37	**SUBMITTED AT HEARING –** Appendix of BC Hydro's long term goals
B-38	**SUBMITTED AT HEARING –** BC Hydro Undertaking dated November 22, 2006 – Transcript Volume 7, Page 779, Line 23
B-39	**SUBMITTED AT HEARING –** BC Hydro Undertaking dated November 23, 2006 – Transcript Volume 8, Page 1011, Lines 3 to 4
B-40	**SUBMITTED AT HEARING** – BC Hydro Undertaking dated November 23, 2006 – Transcript Volume 8, Page 944, Line 6
B-41	**SUBMITTED AT HEARING** – BC Hydro Undertaking dated November 23, 2006 – Transcript Volume 8, Page 1011, Lines 4-6
B-42	**SUBMITTED AT HEARING** – BC Hydro Undertaking dated November 23, 2006 – Transcript Volume 9, Page 1177, Line 7
B-43	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 9, Page 1237
B-44	**SUBMITTED AT HEARING** – Excerpt from "2006 … IEP Report, Chapter 4 …"
B-45	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 10, Page 1397
B-46	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 10, Page 1396

Exhibit No.	Description
B-47	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 9, Page 1137 to 1139
B-48	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 11, Page 1419
B-49	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 11, Page 1520
B-50	**SUBMITTED AT HEARING** – Commission Information Request No. 1.170.2 to 1.170.4 and 1.170.2 Attachment 1
B-51	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 8, Page 1065
B-52	**SUBMITTED AT HEARING** – Response to Undertaking at Transcript Volume 11, Page 1596, Lines 10 to 16
B-53	**SUBMITTED AT HEARING** – Response to Undertaking at Transcript Volume 10, Page 1298, Lines 2 to 7
B-54	**SUBMITTED AT HEARING** – Response to Undertaking at Transcript Volume 8, Page 1083, Line 6
B-55	**SUBMITTED AT HEARING** – Response to Undertaking at Transcript Volume 10, Pages 1469, Line 24
B-56	**SUBMITTED AT HEARING** – Response to Undertaking at Transcript Volume 12, Page 1681, Line 26; Page 1682, Line 21
B-57	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 11, Page 1612
B-58	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 11, Page 1548
B-59	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 11, Page 1550
B-60	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 13, Page 1881
B-60A	**SUBMITTED AT HEARING** – Response to Information Request at Transcript Volume 13, Page 1881, Line 17 to Page 1882, Line 22

Exhibit No.	Description
B-61	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1721
B-62	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 13, Page 1956
B-63	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 15, Page 2293
B-64	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 11, Page 1578
B-65	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1807 to 1808
B-66	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1961 to 1963
B-67	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2217 to 2218
B-68	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 10, Page 1383, Line 15 to Page 1384, Line 5
B-69	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 15, Page 2376, Line 9 to Page 2377, Line 5
B-70	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 16, Page 2449, Line 25
B-71	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 16, Page 2421, Line 22 to Page 2422, Line 8
B-72	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 16, Page 2464, Line 10 to Page 2468, Line 5
B-73	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 16, Page 2532, Lines 4 to 8
B-74	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 11, Page 1647, Lines 9 to 14
B-75	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1706, Line 20 to Page 1707, Line 16

Exhibit No.	Description
B-76	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1713, Line 13 to Page 1714, Line 3
B-77	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1795, Lines 19 to 24
B-78	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 13, Page 1890, Lines 2 to 8
B-79	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 13, Page 1892, Line 16 to Page 1893, Line 14
B-80	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 13, Page 2008, Line 14 to Page 2009, Line 4
B-81	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2072, Lines 13 to 20
B-82	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2077, Lines 3 to 24
B-83	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2088, Line 6 to Page 2089, Line 12
B-84	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2168, Line 22 to Page 2169, Line 10
B-85	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 9, Page 1277, Lines 12 to 19
B-86	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 16, Page 2578, Line 7 to Page 2579, Line 2
B-87	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1722, Line 16 to Page 1723, Line 5
B-88	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 12, Page 1776, Lines 3 to 14
B-89	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2029, Line 13 to Page 2031, Line 20
B-90	**SUBMITTED AT HEARING –** Response to Information Request at Transcript Volume 14, Page 2024, Line 25 to Page 2025, Line 9

Exhibit No.	Description
B-91	Response to Information Request at Transcript Volume 12, Page 171~ Lines 4 to 11
B-92	Response to Information Request at Transcript Volume 13, Page 1824, Line 9 to Page 1825, Line 16
B-93	Response to Information Request at Transcript Volume 15, Page 2237, Lines 1 to 17
B-94	Response to Information Request at Transcript Volume 15, Page 2239, Line 19 to Page 2240, Line 11 **Note:** This is the incorrect version which was filed as Exhibit B-94 on December 21, 2006 – please see B-94A for the correct version
B-94A	Letter dated January 4, 2007, filing responses to Undertaking to Transcript Volume 15, Page 2239, Line 19 to Page 2240, Line 11 **Note:** Incorrect version was filed as Exhibit B-94 on December 21, 2006 – this is the correct version
B-95	Response to Information Request at Transcript Volume 15, Page 2240, Line 13 to Page 2241, Line 17
B-96	Response to Information Request at Transcript Volume 16, Page 2539, Lines 8 to 13 and Page 2584, Line 24
B-97	Response to Information Request at Transcript Volume 17, Page 2640, Line 21 to Page 2641, Line 16
B-98	Response to Information Request at Transcript Volume 18, Page 2696, Lines 6 to 16
B-99	Response to Information Request at Transcript Volume 18, Page 2773, Lines 2 to 8
B-100	Response to Information Request at Transcript Volume 19, Page 2866, Line 20
B-101	Response to Information Request at Transcript Volume 19, Page 2867, Line 26 to Page 2868, Line 8
B-102	Joint letter from BC Hydro and BCTC dated December 21, 2006 filing statement to provide clarity for the LTAP/CRPs (Exhibit C7-10)
B-103	Response to Information Request at Transcript Volume 12, Page 1736, Lines 5 to 13
B-104	Response to Information Request at Transcript Volume 19, Page 2931, Line 11 to Page 2933, Line 5
B-105	Response to Information Request at Transcript Volume 20, Page 3173, Line 15

Exhibit No.	**Description**
B-106	**SUBMITTED AT HEARING –** Extract from "RFP, Supply of Electricity for the BC Hydro Integrated System, December 1994", Pages 19 through 22
B-107	**SUBMITTED AT HEARING –** Province of British Columbia, Policy Statement, Independent Power Supply to BC Hydro
B-108	**SUBMITTED AT HEARING –** Extract from DTLR Multi-Criteria Analysis Manual
B-109	**SUBMITTED AT HEARING –** News Release from the BC Government "Wind Power Policy Supports Alternative Energy Industry" dated October 14, 2005, with attached "Land Use Operational Policy, Wind Power Projects"
B-110	**SUBMITTED AT HEARING –** BC Ministry of Energy & Mines, IPPS and British Columbia's Electricity Needs, Fraser Basin Council Workshop, March 16, 2005
B-111	**SUBMITTED AT HEARING –** Response to Undertaking at Transcript Volume 20, Page 3111, Line 16 to Page 3112 Line 13
B-112	**SUBMITTED AT HEARING –** Witness Aid No. 2 entitled "Appendix A: Energy Efficiency Plan
B-113	**SUBMITTED AT HEARING –** Tables: 2005 BC Control Area Load Report; 2005 BC Control Area Export; and Import (US and Alberta) and 2005 BC Control Area Load and Export Data
B-114	**SUBMITTED AT HEARING –** Document entitled "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations: Report on Phase 2: System Performance Evaluation"
B-115	**SUBMITTED AT HEARING –** Response to IPPBC Information Request at Transcript Volume 20, Page 3005, Line 21 to Page 3006, Line 5
B-116	**SUBMITTED AT HEARING –** Response to JIESC Information Request at Transcript Volume 20, Page 3041, Line 22 to Page 3042, Line 8
B-117	**SUBMITTED AT HEARING –** Response to JIESC Information Request at Transcript Volume 20, Page 3069, Lines 3 to 13
B-118	**SUBMITTED AT HEARING –** Response to JIESC Information Request at Transcript Volume 20, Page 3062, Lines 18 to 26
B-119	**SUBMITTED AT HEARING –** Response to Commission Panel Information Request at Transcript Volume 22, Page 3440, Line 15 to Page 3441, Line 2

Exhibit No.	Description
B-120	Letter dated January 19, 2007 filing response to IPPBC Undertaking at Transcript Volume 20, Page 2973, Line 19 to Page 2974, Line 3
B-121	Response to IPPBC Undertaking at Transcript Volume 20, Page 2985, Line 22 to Page 2986 Line 13, and Page 3005 Lines 4 to 10
B-122	Response to IPPBC Undertaking at Transcript Volume 20, Page 2988, Line 16 to Page 2989 Line 8
B-123	Response to IPPBC Undertaking at Transcript Volume 20, Page 2997, Line 14 to Page 2998 Line 23 and Page 3006, Lines 10 to 22
B-124	Response to IPPBC Undertaking at Transcript Volume 20, Page 3023, Line 6 to Page 3024 Line 8
B-125	Response to JIESC Undertaking at Transcript Volume 20, Page 3044, Line 11 to 24
B-126	Response to BCOAPO Undertaking at Transcript Volume 20, Page 3127, Line 8 to 13
B-127	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3197, Line 3, Page 3197 Line 9
B-128	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3218, Line 6 to Page 3219, Line 10
B-129	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3220, Lines 6 to 12
B-130	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3265, Line 19 to Page 3266, Line 12
B-131	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3273, Lines 2 to 19
B-132	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3279, Line 20 to Page 3280, Line 11
B-133	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3295, Line 6, to Page 3296, Line 1
B-134	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3301, Line 23, to Page 3303, Line 3

Exhibit No.	**Description**
B-135	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3315, Line 18, Page 3316, Line 5
B-136	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3316, Line 19, Page 3317, Line 5
B-137	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3321, Line 10, Page 3322, Line 15
B-138	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3322, Line 17 to 24
B-139	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3341, Lines 5 to 11
B-140	Response to Commission Panel Undertaking at Transcript Volume 22, Page 3387, Line 21, to Page 3389, Line 7
B-141	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3199, Lines 13 to 22
B-142	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3200, Lines 5 to 23
B-143	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3200, Line 26 to Page 3201, Line 26
B-144	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3202, Lines 11 to 18
B-145	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3203, Line 2 to Page 3205, Line 9
B-145A	Revised response received February 8, 2007, to Commission Counsel Undertaking at Transcript Volume 21, Page 3205, Line 9
	REMOVED – This should be Exhibit B-146A
B-146	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3213, Lines 6 to 10, and Transcript Volume 22, Page 3370, Line 4 to Page 3371, Line 7
B-146A	Revised response received February 8, 2007, to Commission Counsel Undertaking at Transcript Volume 21, Page 3213, Lines 6 to 10, and Transcript Volume 22, Page 3370, Line 4 to Page 3371, Line 7

Exhibit No.	Description
B-146B	Letter received February 13, 2007, filing Errata to incorrect reference in Exhibit B-146A on Page 14, Section 1
B-147	Response to Commission Counsel Undertaking at Transcript Volume 21, Page 3267, Lines 15 to Page 3268, Line 1 and Transcript Volume 22, Page 3369, Lines 1 to 9
B-148	Response to Commission Panel Undertaking at Transcript Volume 22, Page 3367, Line 17 to Page 3368, Line 19, and Page 3439, Line 24 to Page 3440, Line 8
B-149	Response to Commission Panel Undertaking at Transcript Volume 22, Page 3410, Line 11, to Page 3411, Line 23
B-150	Letter dated February 15, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
B-151	Letter dated February 28, 2007 filing comments on the BC Energy Plan
B-152	BC Hydro letter dated March 13, 2007 responding to Exhibit No. A-47 and the submissions of SCCBC, BCSEA, PVEA and Vanport, dated March 12, 2007

INTERVENOR DOCUMENTS

C1-1	**LC LINE CONTRACTORS' ASSOCIATION (P.J. HATCH) –** Received online registration dated February 6, 2006 from P.J. Hatch requesting Intervenor Status **- WITHDRAWN -**
C2-1	**CITY OF PORT MOODY (BERT TULLOCH) –** Received online registration dated April 6, 2006 from Bert Tulloch, Manager of Revenues & Taxation, City of Port Moody requesting Intervenor Status
C3-1	**HOWE SOUND PULP & PAPER LIMITED PARTNERSHIP** - Received online registration dated April 11, 2006 from Pierre G. Lamarche requesting Intervenor Status
C4-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO) -** Received letter dated April 12, 2006 from Jim Quail requesting Intervenor Status and for Leigh Worth, Counsel
C4-2	Email dated April 18, 2006 requesting the addition of Leigha Worth as co-counsel

Exhibit No.	Description
C4-3	Received email dated April 19, 2006 requesting Intervenor Status for Bill Harper of Econalysis Consulting Services
C4-4	Letter dated May 4, 2006 requesting the adjournment of the Procedural Conference schedule for May 19, 2006
C4-5	Letter dated May 8, 2006 responding to letter from Intervenor (Exhibit C15-2) and filing additional comments on the proceedings and interim rates
C4-6	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C4-7	Letter dated July 7, 2006 filing Information Request No. 2 to BC Hydro regarding the Project Evaluation Evidence
C4-8	Letter dated July 18, 2006 filing comments and suggestions on the use of the web audio broadcast conferencing of Procedural Conference of August 1, 2006
C4-9	Information Request No. 3 on the Amended LTAP (Exhibit B1-E)
C4-10	Letter dated October 12, 2006 filing response to the Commission's request for Intervenors to file their positions regarding the F2006 Call Report as Evidence (Exhibit A-20)
C4-11	Letter dated November 6, 2006 filing request for public disclosure of the LTEPA Amending Agreement and the Amended and Restated LTEPA
C4-12	Email dated November 8, 2006 filing Court of Appeal Decision for JIESC regarding a decision of a Chambers Judge dated April 12, 2005 refusing Leave to Appeal Orders of the Commission regarding an Energy Purchase Agreement (EPA) between BC Hydro and Duke Point Power
C4-13	**SUBMITTED AT HEARING -** BCOAPO Cross Examination Documents
C4-14	**SUBMITTED AT HEARING –** "Exhibit B to Testimony of Mary Hemmingsen, Preliminary"
C4-15	**SUBMITTED AT HEARING –** "Exhibit B to Testimony of Richard Rosenzweig"
C4-16	**SUBMITTED AT HEARING –** BC Hydro IEP/LTAP, Panel 5, BCOAPO Cross Examination Reference Documents
C4-17	**SUBMITTED AT HEARING –** BCOAPO Information Request No. 2.8.1 from 2006 REAP and one-page Excerpt from Testimony of Mary Hemmingsen
C4-18	**SUBMITTED AT HEARING –** BC Hydro IEP/LTAP 2006 BCOAPO Cross-Examination documents, BC Hydro Panel 7

Exhibit No.	Description
C4-19	Email dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C4-20	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C4-21	E-mail dated March 13, 2007 stating that BCOAPO had nothing to add to its Argument arising from the Throne Speech
C5-1	**TERASEN GAS INC. (TGI)** - Received letter dated April 13, 2006 from Tom Loski requesting Intervenor Status
C5-2	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C5-3	Letter dated June 9, 2006 supporting BC Hydro's request (Exhibit B-8) for an extension to the Information Responses filing date
C5-4	Letter dated July 10, 2006 filing Information Requests No. 1 on Project Evaluation Evidence to BC Hydro (Exhibit B-11)
C5-5	Letter dated July 21, 2006 filing comments on the use of the web audio broadcast conferencing of Procedural Conference of August 1, 2006
C5-6	Letter dated August 21, 2006 filing responses to Commission Information Request No. 1 (Exhibit A-16)
C5-7	**SUBMITTED AT HEARING –** Extract from "2004 Integrated Electricity Plant, Part 5 … Appendix B: Natural Gas Price Forecast Descriptions"
C5-8	**SUBMITTED AT HEARING –** Extract from "Canadian Natural Gas – review of 2004 & Outlook to 2020, January 2006 …"
C5-9	**SUBMITTED AT HEARING –** Witness Aid regarding Exhibit B-16, Response to Commission Information Request No. 3.32.1
C6-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** - Received letter dated April 13, 2006 from Christopher Weafer, Owen Bird requesting Intervenor Status
C6-2	Letter dated August 3, 2006 filing support of BC Hydro's proposed rate design application and comments on process and schedule

Exhibit No.	**Description**
C6-3	Letter dated September 8, 2006 from Christopher Weafer, Owen Bird filing Information Request No. 3 to BC Hydro
C6-4	Letter dated October 12, 2006 filing response to the Commission's request for Intervenors to file their positions regarding the F2006 Call Report as Evidence (Exhibit A-20)
C6-5	**SUBMITTED AT HEARING** – Commercial Energy Consumers Association of British Columbia, Information Request No. 1.2.6 and 1.2.5, Dated July 5, 2006
C6-6	**SUBMITTED AT HEARING –** Table: Supplementary Information – Discounted ($000's)
C6-7	**SUBMITTED AT HEARING –** Report of Proceedings (Hansard) of the Select Standing Committee on Crown Corporations, dated June 11, 2003
C6-8	Letter dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C6-9	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C7-1	**BRITISH COLUMBIA TRANSMISSION CORPORATION (BCTC)** - Received letter dated April 18, 2006 from Marcel Reghelini, Director, Regulatory Affairs requesting Intervenor Status
C7-2	Letter dated May 11, 2006 filing partial response to Commission's Information Request (Exhibit A-3: 1.27.1, 1.43.1, 1.44.3, 1.93.1, 1.93.2, 1.124.1, 1.202.1, 1.202.2, 1.228.2) to BC Hydro
C7-3	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C7-4	Letter dated July 5, 2006 filing responses to Commission Information Request No. 2 and Intervenor Information Request No. 1
C7-5	Letter dated July 17, 2006 filing comments on the use of the web audio broadcast conferencing of Procedural Conference of August 1, 2006
C7-6	Letter dated September 29, 2006 filing responses to Commission Information Request No. 4 to British Columbia Hydro and Power Authority - BCUC IR 4.453.1 and BCUC IR 4.453.2
C7-7	Letter dated October 6, 2006 filing Evidence

Exhibit No.	Description
C7-8	Letter dated November 1, 2006 filing response to Commission and BC Hydro's Information Request No. 1, including excel attachment
C7-9	**SUBMITTED AT THE HEARING** - Letter dated November 21, 2006 filing Direct Evidence of Cameron Lusztig; Paul Choudhury, P.Eng.; and Philip Park, P.Eng.
C7-10	Joint letter from BC Hydro and BCTC dated December 21, 2006 filing statement to provide clarity for the LTAP/CRPs (Exhibit B-102)
C8-1	**ECONALYSIS CONSULTING SERVICES** - Received email dated April 19, 2006 requesting Intervenor Status for Bill Harper
	EXHIBIT WITHDRAWN – RENUMBERED AS C4-3
C9-1	**GREEN ISLAND ENERGY LTD.** - Received online registration dated April 19, 2006 from Sean Ebnet requesting Intervenor Status
C10-1	**CATALYST PAPER CORPORATION (CPC)** - Received online registration dated April 19, 2006 from Dennis Fitzgerald requesting Intervenor Status
C10-2	**Withdrawn – Posted in error**
C10-3	**Withdrawn – Posted in error**
C11-1	**CLOUDWORKS ENERGY INC.** - Received online registration dated April 19, 2006 from John Johnson requesting Intervenor Status
C11-2	Email received May 17, 2006 declining attendance at the Procedural Conference and filing Information Request No. 1
C11-3	Email received July 14, 2006 advising participation in audio conferencing of Procedural Conference of August 1, 2006
C12-1	**WEST FRASER TIMBER CO. LTD.** - Received fax dated April 28, 2006 requesting Intervenor Status for Dave Humber and Bill Legrow
C13-1	**PEACE RIVER REGIONAL DISTRICT** - Received letter dated April 27, 2006 requesting Intervenor Status for Harald Hansen, Administrator
C14-1	**ELK VALLEY COAL CORPORATION (EVCC)** - Received email dated May 3, 2006 requesting Intervenor Status

Exhibit No.	Description
C15-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated May 5, 2006 requesting Intervenor status from R. Brian Wallace
C15-2	Letter dated May 5, 2006 filing comments on the filing of documents by the applicant and Regulator Timetable for filing Information Requests
C15-3	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C15-4	Letter received July 10, 2006 filing Information Request No. 1 to BC Hydro regarding the Evidence on Project Evaluation
C15-5	Letter dated July 21, 2006 filing comments on the use of the web audio broadcast conferencing
C15-6	**SUBMISSION AT HEARING** - JIESC Handout
C15-7	Letter dated October 13, 2006 filing response to the Commission's request for Intervenors to file their positions regarding the F2006 Call Report as Evidence (Exhibit A-20)
C15-8	Letter dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C15-9	Email dated February 14, 2007 filing amendment to date reference
C15-10	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C15-11	Letter dated March 12, 2007 filing response to BC Hydro's Reply Argument related to the Throne Speech (Exhibit A-47)
C16-1	**VAMOS, GEZA** - Received online registration dated May 4, 2006 requesting Intervenor Status
C17-1	**FORTISBC INC. -** Received online registration dated May 4, 2006 requesting Intervenor Status for Joyce Martin
C17-2	Letter dated May 12, 2006 filing notice for attendance at the Procedural Conference and filing comments on the issues identified for consideration at the Procedural Conference

Exhibit No.	**Description**
C17-3	Letter dated July 21, 2006 filing response and comments on the use of the web audio broadcast conferencing
C18-1	**INDEPENDENT POWER PRODUCERS OF BC (IPPBC) –** Letter dated May 9, 2006 requesting Intervenor status for David Austin of Tupper Jonsson & Yeadon and Mr. Steve Davis, President
C18-2	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C18-3	Letter dated July 10,2006 filing Information Request No. 1 to BC Hydro regarding the Evidence on Project Evaluation
C18-4	Letter dated September 8, 2006 filing Information Request No. 3 to BC Hydro
C18-5	Letter dated October 6, 2006 filing Evidence
C18-6	Letter dated November 2, 2006 filing response to the Commission's Information Request No. 1 and comments
C18-7	**SUBMITTED AT HEARING –** Document entitled "Guidelines for Ranking Seismic Upgrade Projects" filed by BCTC in the 2004 Capital Plan Application in Response to Commission Information Request No. 6.7
C18-8	**SUBMITTED AT HEARING –** BC Hydro Service Plan 2006/07 to 2008/09
C18-9	**SUBMITTED AT HEARING –** BC Hydro F07/08 Revenue Requirements Application Appendix L – Aberfeldie Redevelopment
C18-10	**SUBMITTED AT HEARING –** Appendix B: Consultative Committee Comments on the BC Hydro 1995 Integrated Electricity Plan
C18-11	**SUBMITTED AT HEARING –** BC Hydro 1995 Integrated Electricity Plan
C18-12	**SUBMITTED AT HEARING –** BC Hydro F07/08 Revenue Requirements Application Appendix J – Capital Expenditures – John Hart
C18-13	**SUBMITTED AT HEARING –** BC Hydro Response to BCOAPO Information Request No. 1.12.1 from the F07/08 Revenue Requirements Application
C18-14	**SUBMITTED AT HEARING –** BC Hydro Response to BCOAPO Information Request No. 1.9.1 from the F07/08 Revenue Requirements Application
C18-15	**SUBMITTED AT HEARING –** BC Hydro Response to Commission Information Request No. 1.5.1 - Attachment 1 from the Generation Strategic Asset Plan

Exhibit No.	Description
C18-16	**SUBMITTED AT HEARING –** BC Hydro Response to BCOAPO Information Request No. 1.30.1 – Attachment 1 – Detailed EAR Business Case – IO&RM Energy Trading and Risk Management System
C18-17	**SUBMITTED AT HEARING –** Independent Power Producers Association of BC, Information Request No. 1.20.1, dated March 2, 2000
C18-18	**SUBMITTED AT HEARING –** Independent Power Producers Association of BC, Information Request No. 1.20.2, dated March 2, 2000
C18-19	**SUBMITTED AT HEARING –** Chart entitled "BC Hydro Monthly Demand vs. Minimum Generation"
C18-20	**SUBMITTED AT HEARING –** Integrated Electricity Plan, an Update to the 1995 IEP, January 2000
C18-21	**SUBMITTED AT HEARING –** Extract from "BC Hydro 1995 Integrated Electricity Plan"
C18-22	**SUBMITTED AT HEARING –** Commission Information Request 1.2.26, dated January 23, 2004
C18-23	**SUBMITTED AT HEARING –** Document entitled "LAWPD Increases Supply of Clean energy for angelenos by 50 Megawatts"
C18-24	**SUBMITTED AT HEARING –** Excerpt from "BCUC Vancouver Island Energy Corporation … Decision, September 8, 2003…"
C18-25	**SUBMITTED AT HEARING –** Excerpt from "BCUC Vancouver Island Energy Corporation … Decision, September 8, 2003…"
C18-26	**SUBMITTED AT HEARING –** Excerpt from BCUC Decision, 1994/95 Revenue Requirements Application, November 24, 1994
C18-27	**SUBMITTED AT HEARING –** Excerpt from BC Hydro 1999 Annual Report, 2004/05 – 2005/06 Revenue Requirements Application and BC Hydro 2006 Annual Report
C18-28	**SUBMITTED AT HEARING –** Excerpt from Budget and Fiscal Plan 2006/07 – 2008/09 and BC Hydro's Service Plan from 2006 to 2008-09
C18-29	**SUBMITTED AT HEARING –** Excerpt from BC Hydro's 2005-2006 Service Plan and Extracts from 2004/05 to 2006/07 Service Plan
C18-30	**SUBMITTED AT HEARING –** Page 140/141 from Alcan LTEPA Transcript, Volume 2, December 6, 2006 with attached Commission Information Request No. 4.445.1

Exhibit No.	Description
C18-31	Letter dated December 22, 2006 filing the resumes of its Witness Panel
C18-32	**SUBMITTED AT HEARING –** Excerpt of document dated August 27, 1996, with covering letter to the Honourable Dan Miller
C18-33	**SUBMITTED AT HEARING –** Extract from “Request for Proposal, Supply of Electricity for the BC Hydro Integrated System, December 1994”
C18-34	**SUBMITTED AT HEARING –** BC Hydro News Release dated February 1
C18-35	**SUBMITTED AT HEARING –** Extract of Page 13 from Argument of IPPBC
C18-36	**SUBMITTED AT HEARING –** Document entitled “Transmission Expansion Policy Implementation, Potential Opportunities, British Columbia Transmission Corporation”, Expansion Policy Presentation 23 October, 2006
C18-37	Letter dated January 22, 2007 filing Undertaking at Transcript Volume 23, Page 3707, Line 7
C18-38	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C19-1	**BROOKFIELD ENERGY MARKETING INC. –** Letter dated May 9, 2006 requesting Interested Party status from Peter Bettle, Manager, Market Affairs
	Previously D-2
C20-1	**LONE PRAIRIE COMMUNITY ASSOCIATION -** Received online registration dated May 10, 2006 requesting Intervenor Status for Joyce Thayer
C21-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) -** Received online registration dated May 10, 2006 requesting Intervenor Status for Thomas Hackney
C21-2	Email dated May 11, 2006, withdrawing as a Intervenor
C22-1	**ZE POWERGROUP -** Received online registration dated May 10, 2006 requesting Intervenor Status for Olga Gorstenko
C23-1	**COMSTOCK ENERGY INC. -** Received email request dated May 9, 2006 requesting Intervenor Status for Patrick J. McBride and Jack Larsen
C24-1	**WORLD FEDERALISTS OF CANADA (VICTORIA BRANCH) -** Received fax request dated May 10, 2006 requesting Intervenor Status by William A. Pearce, Q.C.

Exhibit No.	**Description**
C24-2	Email dated June 27, 2006 filing request for copies of Orders issued under Section 45(4)
C24-3	Email dated October 4, 2006 filing Evidence/Preliminary Submission
C24-3A	**SUBMITTED AT HEARING –** Revised Evidence/Preliminary Submission
C24-4	Responses to Commission Information Request No. 1 received October 26, 2006
C24-5	Letter dated October 31, 2006 filing supplemental information response to Commission Information Request No. 1 on Evidence filed (Exhibit A-22)
C24-6	Letter dated November 1, 2006 filing response to Commission Information Request No. 1 on Evidence filed (Exhibit A-22)
C24-7	Letter dated November 18, 2006 requesting leave to file the Stern Report as evidence. Executive Summary of the Stern Report attached.
C25-1	**SIERRA CLUB OF CANADA BRITISH COLUMBIA (SCCBC), BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) AND THE PEACE VALLEY ENVIRONMENTAL ASSOCIATION (PVEA) -** Received web posting from William J. Andrews dated May 11, 2006, requesting Intervenor Status
C25-2	Email received May 17, 2006 from Thomas Hackney requesting to be added to the distribution list
C25-3	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C25-4	Letter dated July 10, 2006 filing Information Request No. 2 on Project Evaluation Evidence to BC Hydro (Exhibit B-11)
C25-5	Letter dated July 14, 2006 filing response to Commission’s request for participants’ responses regarding BC Hydro’s request for an audio broadcast of the upcoming public hearing over the Internet (Exhibit A-11)
C25-6	Letter dated September 5, 2006 filing request to Commission to direct BC Hydro to respond to specific Information Requests
C25-7	Letter dated September 8, 2006 filing Information Request No. 3 to BC Hydro on the Amended LTAP
C25-8	Letter dated September 13, 2006 from William J. Andrews – Reply to BC Hydro’s September 12, 2006 response to SCCBC

Exhibit No.	Description
C25-9	Letter dated September 26, 2006 from William J. Andrews filing response to Commission's request (Exhibit A-18) regarding the F2006 Call Report to be accepted as evidence and supporting comments
C25-10	Letter dated October 6, 2006 from William J. Andrews filing Evidence
C25-11	Letter dated October 11, 2006 from William J. Andrews filing DSM Evidence and Testimony of John Plunkett, Green Energy Economics Group
C25-12	Letter dated October 11, 2006 from William J. Andrews filing revised Evidence of Robert Fagan with Attachment 4 (Exhibit C25-10)
C25-13	Letter dated October 12, 2006 from William J. Andrews filing response to the Commission's request for Intervenors to file their positions regarding the F2006 Call Report as Evidence (Exhibit A-20)
C25-14A	Letter dated November 1, 2006 from William Andrews filing response to Commission Information Request No. 1 on Evidence filed (Exhibit A-21)
C25-14B	Letter dated November 1, 2006 from William Andrews filing response to BC Hydro's Request No. 1 on Evidence filed (Exhibit B-23)
C25-14C	**SUBMITTED AT HEARING –** Revised Attachment to Response to BCUC Information Request SCCBC 18.1
C25-15	Letter dated November 3, 2006 filing request for clarification on the evidence regarding the confidential nature of the LTEPA Amending Agreement and the Amended and Restated LTEPA
C25-16	**SUBMITTED AT HEARING –** SCCBC et al, BC Hydro Witness Panel Six Cross-Examination Materials
C25-17	Response to Undertaking at Transcript Volume 24, Page 3820
C25-18	Response to Undertaking at Transcript Volume 24, Page 3839
C25-19	Response to Undertaking at Transcript Volume 24, Page 3843
C25-20	Letter dated January 19, 2007 filing response to Undertaking at Transcript Volume 24, Pages 3848 to 3850
C25-21	Letter dated January 19, 2007 filing response to Undertaking at Transcript Volume 24, Pages 3853 to 3855

Exhibit No.	Description
C25-22	Letter dated January 25, 2007 filing response to Undertaking at Transcript Volume 24, Pages 3825 to 3826
	EVIDENCE NOT PART OF RECORD - PLEASE SEE EXHIBIT A-41
C25-23	Letter dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C25-24	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C25-25	Letter dated March 12, 2007 filing response to BC Hydro's Reply Argument related to the Throne Speech (Exhibit A-47)
C26-1	**BURKE MOUNTAIN NATURALISTS -** Received online registration dated May 12, 2006 requesting Intervenor Status from Elaine Golds
C26-2	Received email dated May 12, 2006 filing statement regarding the nature of the Society's interests
C27-1	**SEA BREEZE PACIFIC REGIONAL TRANSMISSION SYSTEM, INC -** Received online registration dated May 12, 2006 requesting Intervenor Status from James Griffiths
C28-1	**SEA BREEZE ENERGY INC. -** Received online registration dated May 12, 2006 requesting Intervenor Status
C28-2	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C29-1	**DOKIE WIND ENERGY INC. -** Received online registration dated May 12, 2006 requesting Intervenor Status by Ron Percival
C30-1	**CITY OF NEW WESTMINSTER -** Received email dated May 12, 2006 requesting Intervenor Status by Penny Cochrane of Willis Energy Services Ltd.
C31-1	**COLUMBIA POWER CORPORATION (CPC) -** Received email dated May 12, 2006 requesting Intervenor Status for Bruce Duncan and Fred J. Weisberg
C31-2	Letter dated June 5, 2006 filing Information Request No. 1 to BC Hydro
C31-3	Letter dated July 8, 2006 filing Information Request No. 1 to BC Hydro regarding the Evidence on Project Evaluation

Exhibit No.	Description
C31-4	Letter dated July 17, 2006 filing request to Commission to direct BC Hydro to respond to specific Information Requests
C31-5	Letter dated September 8, 2006 filing Information Request No. 3 to BC Hydro
C31-6	Letter dated October 6, 2006 filing Evidence
C31-7	Email received dated November 1, 2006 filing response to Commission Information Request No. 1 on Evidence filed (Exhibit A-24)
C31-8	Letter dated November 23, 2006 from Columbia Power Corporation filing the curriculum vitae of Dr. Marvin Shaffer
C31-9	**SUBMITTED AT THE HEARING –** One Page Letter dated March 2, 1990 from BC Hydro, with two attached Orders-In-Council
C31-10	**SUBMITTED AT THE HEARING –** One Page Document titled "Water Rentals – Illustrative Table"
C31-11	**SUBMITTED AT THE HEARING –** Excerpt from "Report of the Independent Power Producers Review Panel – August 27, 1996"
C31-12	**SUBMITTED AT HEARING –** Letter dated August 19, 2005 from G. Isherwood (FortisBC) and T. Morris (BC Hydro) to the Commission
C31-13	**SUBMITTED AT HEARING –** Letter dated November 18, 2005 with Attached "Submissions of the Government of British Columbia"
C31-14	**SUBMITTED AT HEARING –** Commission Order G-41-06 and attached Reasons for Decision
C31-15	Letter dated January 19, 2007 filing responses to Undertaking at Volume 22, Page 3549, Line 22 to page 3551, Line 9
C31-16	Letter dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C31-17	Letter dated February 28, 2007 filing comments on the BC Energy Plan
C32-1	**SEA BREEZE POWER CORP. -** Received online registration dated May 17, 2006 requesting Intervenor Status for Eugene Hodgson/VP Government Affairs
C32-2	Email received dated May 29, 2006 from Eugene Hodgson withdrawing as Intervenor

Exhibit No.	Description
C33-1	**CANADIAN OFFICE AND PROFESSIONAL UNION (COPE) -** Received letter dated May 25, 2006 requesting Intervenor Status for Gwenne Farrell and Lori Winstanley
C34-1	**BERTSCH, LUDO –** Received online web registration dated June 9, 2006 requesting Intervenor Status
C34-2	Letter dated October 12, 2006 filing response to the Commission's request for Intervenors to file their positions regarding the F2006 Call Report as Evidence (Exhibit A-20)
C34-3	**SUBMITTED AT THE HEARING** – Three page document – "West Coast Vancouver Island Aquatic Management Board", Numbered A-1, B-1 and B-2
C34-4	**SUBMITTED AT THE HEARING** – Document "Regional IEP Meeting 2nd Round, Fall 2005", Number C-1
C34-5	**SUBMITTED AT THE HEARING** – One Page "BC Hydro Integrated Electricity Planning Committee – Meeting #6", Numbered E-1
C34-6	**SUBMITTED AT THE HEARING** – One page "Tab 6-4 – Attributed Results Summary", Numbered F-1
C34-7	**SUBMITTED AT THE HEARING –** IEP Update Newsletter Fall 2005
C34-8	**SUBMITTED AT THE HEARING –** Copy of Article by Roy MacGregor, from Globe & Mail, November 29, 2006
C34-9	**SUBMITTED AT THE HEARING –** Excerpt – Page 93 from "VITR Project CPCN Application, 7 July 2005
C34-10	Letter dated February 14, 2007 filing comments on matters arising from the Throne Speech (Exhibit A-42)
C34-11	E-mail dated February 28, 2007 filing comments on the BC Energy Plan
C35-1	**EPCOR UTILITIES INC. (EPCOR) –** Received letter dated June 12, 2006 from Sian Barraclough, Manager Regional Markets, Regulatory Affairs, requesting Intervenor Status
C35-2	Letter dated February 28, 2007 providing notice of change of contact

Exhibit No.	Description
C36-1	**WILLIS ENERGY SERVICES LIMITED –** Received online web registration from Paul Willis dated August 2, 2006 requesting Intervenor Status
C37-1	**DISTRICT OF KITIMAT -** Received letter dated September 1, 2006 from John J.L. Hunter, Hunter Litigation Chambers, legal counsel, requesting late Intervenor Status
C37-2	Letter dated September 8, 2006 filing Information Request No. 3 on the Amended LTAP (Exhibit B1-E)
C37-3	Letter dated October 6, 2006 from John J.L. Hunter, Hunter Litigation Chambers filing Evidence
C37-4	Letter dated November 1, 2006 from John J.L. Hunter, Hunter Litigation Chambers filing response to Commission Information Request No. 1 on Evidence filed (Exhibit A-26)
C37-5	Letter dated November 6, 2006 from John J.L. Hunter, Hunter Litigation Chambers filing request for public disclosure
C37-6	Letter dated November 7, 2006 filing submission regarding the Amended and Restated Long-Term Electricity Purchase Agreement (LTEPA) and LTEPA Amending Agreement
C37-7	Email dated November 8, 2006 providing a copy of the decision of Mr. Justice Hutchison in *United Fishermen and Allied Workers' Union v. British Columbia*, [1994] B.C.J. No. 2839 (S.C.)
C38-1	**ALCAN PRIMARY METAL GROUP -** Received letter dated September 11, 2006 from Ken Duke, legal counsel, requesting late Intervenor Status
C38-2	Copy of Schedule 2A – Replacement Electricity Supply Agreement dated August 5, 1997 between the Province and Alcan Aluminium Limited
C39-1	**TENNANT, RICHARD (VANPORT STERILIZERS INC.) -** Received online web registration dated September 15, 2006 requesting late Intervenor Status
C39-2	Fax dated November 15, 2006 filing Request for Leave to File Evidence
C39-3	Fax dated November 21, 2006 filing Evidence
C39-4	**SUBMITTED AT THE HEARING –** Excerpt headed "5.1 Vancouver Island Hydro Projects – (d) Pumped Storage Hydro"

Exhibit No.	**Description**
C39-5	Letter dated March 12, 2007 filing response to BC Hydro's Reply Argument related to the Throne Speech (Exhibit A-47)

INTERESTED PARTY DOCUMENTS

D-1	**ELLIOTT, JOHN –** Web registration dated April 10, 2006 requesting Interested Party status
D-2	**FRASER VALLEY REGIONAL DISTRICT –** Email dated May 11, 2006 requesting Interested Party status from Bob Smith, Air Quality Consultant
D-3	**SIMMONS, TERRY -** Received online registration dated May 12, 2006 requesting Interested Party status
D-4	**NEWCOMB, JOHN -** Received online registration dated May 16, 2006 requesting Interested Party status
D-5	**CHAPMAN, DR. J. D. -** Received letter dated May 25, 2006 requesting Interested Party status and filing letter of comment
D-6	**MARSHAL, M.L. (LAYNE) –** Received online web registration August 22, 2006, requesting Interested Party status

LETTERS OF COMMENT

E-1	Letter of Comment dated May 16, 2006 from Cynthia Van Ginkel, Port Moody, BC
E-2	Letter of Comment dated July 5, 2006 from Greater Victoria Chamber of Commerce
E-3	Letter of Comment dated September 7, 2006 from the Kitamaat Village Council, Kitamaat Village, BC
E-4	Letter of Comment dated December 6, 2006 from Arnold Badke, of the Consulting Engineers of British Columbia (CEBC)