IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

AN APPLICATION FOR APPROVAL OF THE
2008 LONG TERM ACQUISITION PLAN

DECISION

July 27, 2009

Before:

A.J. Pullman, Commissioner and Panel Chair
R.J. Milbourne, Commissioner
M.R. Harle, Commissioner

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ERRATA

British Columbia Hydro and Power Authority
Project No. 3698514/Order G-91-09
2008 Long Term Acquisition Plan

Please note the following amendment to the Commission's July27, 2009 Decision with respect to British Columbia Hydro and Power Authority's 2008 Long Term Acquisition Plan.

Page 114, last line	"efficient discharge permit"
	Should read:
	"effluent discharge permit"

OVERVIEW

These Reasons for Decision are issued in respect of Commission Order G-91-09 issued on July 27, 2009. The Reasons are set out as follows:

Section 1.0 describes the procedural background to the Application and the regulatory and policy framework within which it was made. The Commission Panel considers the overall legislative scheme provided by the *Act*, Ministerial Order M271 (DSM Regulation), SD 10 (self-sufficiency) and other legislation and policy initiatives that inform the Application. It also describes the conduct of the hearing which included an Oral Hearing lasting 13 days and an Oral Phase of Argument.

Section 2.0 addresses jurisdictional matters with emphasis on the scope of the Commission's discretion in reviewing BC Hydro's 2008 LTAP.

Section 3.0 summarizes the specific relief and endorsements sought by BC Hydro.

Section 4.0 summarizes the steps taken by BC Hydro to consult its stakeholders, engage the public, and consult and, if appropriate, accommodate the First Nations whose interests may be affected by matters relevant to the 2008 LTAP.

Section 5.0 reviews BC Hydro's market analysis of natural gas and electricity market prices, GHG offset costs and the value of renewable energy credits.

Section 6.0 reviews BC Hydro's request for primary relief namely a determination that the 2008 LTAP is in the public interest. In section 6.2 the Commission Panel reviews the energy and capacity self-sufficiency obligation in section 3 of SD 10 and determines that BC Hydro has not adequately addressed the self-sufficiency obligation established by SD 10 in its 2008 LTAP. In Section 6.3 it reviews BC Hydro's Load Forecast and approves it. In Section 6.4 it reviews BC Hydro's DSM Plan and finds that it cannot determine whether BC Hydro's DSM Plan complies with section 44.1 of the *Act* and rejects it. In Section 6.5 it reviews BC Hydro's existing and committed resources and endorses BC Hydro's plan to rely on Burrard for 900 MW of dependable capacity. It rejects BC Hydro's plan to reduce its reliance on Burrard to 3,000 GWh/year of energy for planning purposes. In Section 6.6 it reviews the load/resource gap and determines that it cannot endorse a specific volume from the 2008 Clean Power Call.

As a result of having rejected or found deficient a number of material parts of the 2008 LTAP, in Section 6.7 the Commission Panel rejects the 2008 LTAP.

Section 7.0 addresses other relief sought by BC Hydro and Intervenors. The Commission Panel approves the Contingency Resource Plan, as well as expenditures on Site C and the DSM Program. The Commission Panel reviews BC Hydro's Capital Plan review process and addresses the timing of BC Hydro's next LTAP. It makes a number of DSM related findings. Finally, it addresses Terasen's request for relief in respect of Electric Load Avoidance.

Section 8.0 is a summary of the Directives found in this Decision.

1.0 INTRODUCTION

1.1 Procedural Background

On June 12, 2008 British Columbia Hydro and Power Authority ("BC Hydro") filed its 2008 Long Term Acquisition Plan ("2008 LTAP") with the BC Utilities Commission (the "Commission"), pursuant to sections 44.1 and 44.2 of the *Utilities Commission Act* (the "*Act*") seeking, among other things, a Commission determination that the 2008 LTAP is in the public interest as contemplated by section 44.1(6) (a) of the *Act*. Further to that overriding determination, BC Hydro also seeks Commission approval and/or endorsement of several specific matters as particularized in Section 3 of this Decision.

In the covering letter accompanying its Application (Exhibit B-1), BC Hydro also sought approval to amend the LTAP filing cycle from every second calendar year, to a date two years after the Commission's Order in the prior LTAP proceeding. As well, BC Hydro sought approval for its proposal that the Integrated Energy Plan ("IEP") aspect of the LTAP regime, wherein every second LTAP is required to be a combined IEP/LTAP filing, be eliminated, and that IEP analysis be included in its LTAP filings as appropriately determined by BC Hydro.

A procedural conference was held on September 9, 2008 to consider the regulatory timetable. Following the procedural conference, the Commission issued Order G-126-08, establishing two rounds of Information Requests ("IRs"), Intervenor evidence and IRs thereon, and an Oral Hearing to begin on January 8, 2009.

By letter dated November 14, 2008 the Independent Power Producers' Association of British Columbia ("IPPBC") referred the Commission to a communication from BC Hydro to Intervenors concerning, among other things, possible amendments to the Oral Hearing schedule (Exhibit C-17-4). IPPBC sought relief from the deadline for filing Intervenor evidence pending finalization of the schedule. The BC Hydro communication to Intervenors also referenced BC Hydro's intention to seek Commission orders in respect of the Fort Nelson Generating Station Upgrade Project definition and implementation phase expenditure request ("FNGU") and the Mica Units 5 and 6 definition phase expenditure request ("Mica 5/6") in advance of the LTAP Reasons for Decision.

By letter dated November 14, 2008, BC Hydro acknowledged canvassing Intervenors as to their wishes as to how to proceed in light of its intention to file an evidentiary update in respect of the 2008 Load Forecast, the F2006 Call attrition rate updates, and a new resource balance arising as a result (Exhibit B-5).

By letter dated November 17, 2008, the Commission announced a second procedural conference to be held November 27, 2008, to hear submissions from the parties on the above matters, as well as any other issues they wished to address, including the possibility of moving the FNGU matter to a separate proceeding (Exhibit A-6). On November 19, 2008, BC Hydro wrote to the Commission proposing an amended timetable, confirming its request for early orders on FNGU and Mica 5/6 and expressing strong opposition to moving FNGU to a separate hearing and argument phase (Exhibit B-6).

Following its consideration of the submissions received at that procedural conference, on November 28, 2008 the Commission issued Order G-178-08 which:

- granted IPPBC the relief it requested, and established dates for its filing evidence and any IRs arising therefrom (L-56-08);
- amended the regulatory timetable, providing for February 19, 2009 as the commencement date for the Oral Hearing; and
- determined that Mica 5/6 would be dealt with as part of the main 2008 LTAP argument phase, and that the FNGU matter would remain as part of the LTAP evidentiary and argument phases.

BC Hydro filed its Evidentiary Update on December 22, 2008 (Exhibit B-10).

1.2 Regulatory and Policy Framework

The most recent review of BC Hydro's long term resource planning, the 2006 IEP/LTAP Application ("2006 IEP/LTAP"), took place within the context of the Province's 2002 Energy Plan and the May 29, 2003 amendments to the *Act* which added new sections 45 (6.1) and (6.2) to the *Act*. Those sections respectively required public utilities to file certain plans with the Commission and provided the Commission with a broad discretion in its review of those plans. As well as dealing with the specific aspects of the 2006 IEP/LTAP, the Commission Order resulting from that proceeding provided for the consolidation of a number of resource review processes and established the nature and timetable for IEP/LTAP reviews going forward.

By Order G-29-07 dated May 11, 2007, some 29 directives to BC Hydro resulted from the Commission's review of the 2006 IEP/LTAP. These are reproduced, and their disposition detailed, at Appendix C of Exhibit B-1-1 in this proceeding.

Between the filing of the 2006 IEP/LTAP and that of the 2008 LTAP, there have been a number of material developments in the policy and regulatory regime. In particular, in February 2007, the Province published The BC Energy Plan: A Vision for Clean Energy Leadership ("2007 Energy Plan") which included 55 Policy Actions directed towards:

- Energy Efficiency and Conservation (9 actions);
- Electricity (19 actions);
- Alternative Energy (7 actions); and
- Oil and Gas (20 actions).

(Exhibit B-1-1, Appendix B)

Many of these were referenced or otherwise relied on by parties in the course of the proceeding. In its Final Argument, BC Hydro provided as Table 2, a table summarizing the Policy Actions that it saw as relevant to the proceeding, and noted which of those Policy Actions had been given legislative effect:

Table 2: Relevant 2007 Energy Plan Action Items

Policy Action Item No.	Law or Policy
1 - Set an ambitious conservation target to acquire 50% of BC Hydro's incremental resource needs through conservation by 2020	**Policy.** See below under Policy Action No. 3.
3 - Encourage utilities to pursue cost effective and competitive DSM opportunities	**Law** (Legislation - *UCA*). Section 44.1 of the *UCA* requires BC Hydro to take all cost-effective DSM measures first before it resorts to supply side resources.
4 - Explore with BC utilities new rate structures that encourage energy and conservation	**Policy**
10 - Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016	**Law** (Regulation). Section 3 of SD 10 directs the BCUC, in regulating BC Hydro, to use the criterion that BC Hydro is to achieve electricity self-sufficiency by 2016 and each year thereafter, and is to exceed self sufficiency by at least 3,000 gigawatt hours as soon as practicable but no later than 2026
11 - Establish a standing offer (**SOP**) for clean electricity up to 10 megawatts	**Policy, but accepted by the Commission** – The Commission accepted BC Hydro's SOP pursuant to BCUC Order No. G-43-08, and therefore the SOP is a committed resource.
16 - Establish the existing heritage contract in perpetuity	**Law** (Regulation). OIC No. 849 (27 November 2008) establishes the Heritage Contract in perpetuity.
17 - Invest in upgrading and maintaining the heritage asset power plants to retain the ongoing competitive advantage these assets provide to the Province	**Policy**
18 - All new electricity generation projects will have zero net GHG emissions. The 2007 Energy Plan further provides that this target is aimed at new generation projects "interconnected to the grid' (p. 12).	**Law** (Legislation). The *Emissions Standards Act* will require this, although it is not yet in force. For thermal projects greater than or equal to 50 MW, an Environmental Assessment Certificate (**EAC**) is required from the BC Ministers of Energy, Mines and Petroleum Resources and of the Environment (**Responsible Ministers**). The Responsible Ministers have the power to attach conditions to EACs pursuant to Section 17 of the *B.C. Environmental Assessment Act*[112] (***BCEAA***). The Responsible Ministers have required GHG mitigation plans as part of EACs. For thermal projects less than 50 MW, the BC Ministry of Environment (**MOE**) can attach conditions requiring GHG offsets to air emission permits issued pursuant to Section 14 of *EMA*.

Table 2: Relevant 2007 Energy Plan Action Items (continued)

19 - Zero net GHG emissions from existing thermal generation power plans by 2016. The detailed description of Policy Action No. 19 states that this target applies to "existing natural gas and oil fired generating facilities in the interconnected grid".	**Law** (Legislation). See above regarding the *Emissions Standards Act*. All thermal projects require an air emission permit. Pursuant to Section 16 of the *EMA* MOE may amend an air emission permit if it is considered necessary.
20 - Require zero GHG emissions from any coal thermal electricity facilities	**Law** (Legislation). See above in respect of Policy Action No. 18 and No. 19.
21 - Ensure clean or renewable electricity generation continues to account for at least 90% of total generation	**Policy**
22 - Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC hydro may choose to retain Burrard for capacity purposes after 2014.	**Policy**
25 - Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources	**Policy**
26 - Work with BC Hydro and parties involved to continue to improve the procurement process for electricity	**Policy**
31 - Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial Mountain Pine Beetle infestation.	**Policy**

Source: BC Hydro Argument, pp. 48-50

Further to the Energy Plan, on June 25, 2007, the Province issued Special Direction 10 to the Commission, ("SD 10") which, among other things, in Section 3 provides that the Commission in regulating BC Hydro "must use the criterion" that BC Hydro "is to achieve energy and capacity self-sufficiency by becoming capable of:

- meeting, by 2016 and each year thereafter, its electricity supply obligations and
- exceeding, as soon as practicable, but in any event no later than 2026, its electricity supply obligations by at least 3,000 GWh/year [“insurance”] and by the capacity required to integrate that energy in the most cost effective manner

solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities.”

Pursuant to section 1 of SD 10, “electricity supply obligations” are determined by using BC Hydro’s “mid-level forecasts of its energy requirements and peak load, taking into account demand-side management (“DSM”) initiatives that are accepted by the Commission from time to time.” The relevant sections of SD 10 are included in Appendix 1 to this Decision.

On May 1, 2008 certain amendments to the *Act* (the “2008 Amendments”) came into force, including sections 44.1 and 44.2 under which this LTAP is filed. At the same time, subsections 45(6.1) and (6.2), under which the 2006 IEP/LTAP had been filed and reviewed, were repealed. Sections 44.1 and 44.2 are included in Appendix 1 to this Decision.

Subsection 44.1(2) sets out that a public utility is to file with the Commission “in the form and at the times the commission requires” a long-term resource plan which includes:

- an estimate of the demand for energy the public utility would expect to serve if it does not take new DSM measures during the period addressed by the plan;
- a plan of how the public utility intends to reduce its load/resource gap by taking cost-effective DSM measures and an estimate of the energy that the public utility expects to serve after it has taken those measures;
- an explanation as to why the entire load/resource gap cannot be met with DSM measures; and
- a description of the facilities that the public utility intends to construct or extend, and information regarding the energy purchases from other persons the public utility intends to make, to serve demand after all cost-effective DSM measures are taken.

Subsection 44.1(6) gives the Commission the discretion to either accept the LTAP, if the Commission determines that to carry it out would “be in the public interest,” or to reject it, subject to the discretion given the Commission in subsection 44.1(7) to accept or reject “a part” of an LTAP.

Pursuant to subsection 44.1(8), in determining to accept an LTAP, the factors that the Commission “must consider” include:

- the “government’s energy objectives” (44.1(8)(a));
- whether the plan shows that the public utility intends to pursue adequate, cost-effective DSM measures (44.1(8)(c)); and
- the interests of persons in BC who receive or may receive service from the public utility (44.1(8)(d)).

The government’s six energy objectives are set out in section 1 of the *Act* which is included, in part, in Appendix 1 to this Decision. In its Final Argument (pp. 14-15) BC Hydro submits that of the six objectives, four are directly relevant to this review:

- to encourage BC Hydro to reduce green-house gas (“GHG”) emissions;
- to encourage BC Hydro to take DSM measures;
- to encourage BC Hydro to produce, generate, and acquire electricity from clean or renewable resources; and
- to encourage BC Hydro to use innovative energy technologies.

While section 1 of the *Act* now provides a broad definition of demand-side measures, subsection 44.1(2) provides that DSM is the “preferred resource,” and that it must be cost-effective. In its Final Argument, BC Hydro submits that:

- pursuant to subsection 44.1(2)(b), BC Hydro must pursue all cost-effective DSM prior to pursuing any supply side options; and
- pursuant to subsection 44.1(2) (f), BC Hydro must prove why it cannot fill its entire load/resource gap with DSM only.

(BC Hydro Final Argument p. 16, emphasis added)

On November 6, 2008, by Ministerial Order No. M271 ("M271"), the BC Minister of Energy Mines and Petroleum Resources ("MEMPR") enacted the DSM Regulation, which sets out the adequacy requirements for BC Hydro's "plan portfolio," defined in section 1 of the regulation to mean "the class of [DSMs] that is comprised of all the [DSMs] proposed by a public utility in a plan submitted under section 44.1 of the *Act*." The relevant portions of M271 are included in Appendix 1 to this Decision.

In its Argument (p. 17) BC Hydro submits that the DSM Plan submitted as part of the 2008 LTAP is a "plan portfolio" for the purposes of the DSM Regulation, and that only two elements of those set out in section 3 of the DSM Regulation as being required are relevant:

- pursuant to subsection3(a), the DSM Plan must contain a DSM measure 'intended to specifically assist residents of low income households to reduce their energy consumption"; and
- pursuant to subsection 3(c), the DSM Plan must contain an education program for students enrolled in schools in BC Hydro's service area.

Subsection 44.2(1) of the *Act* states that a public utility "may" file with the Commission an expenditure schedule with respect to DSM, capital expenditures, and/or the acquisition of energy from other persons. Subsection 44.2(3) provides that the Commission, after reviewing the expenditure schedule, "must accept" an expenditure schedule if the Commission considers the making of the expenditures in the schedule would be "in the public interest," or "reject" the schedule, subject to subsection 44.2(4) which provides that the Commission may accept or reject a part of an expenditure schedule.

Pursuant to subsection 44.2(5), in considering whether to accept an expenditure schedule, the factors which the Commission must consider include:

- the government's energy objectives;
- the most recent long-term resource plan filed by the public utility pursuant to subsection 44.1;
- whether the DSMs are cost-effective within the meaning prescribed by regulation; and
- the interests of persons who receive or may receive service from the public utility.

Further to the Commission's obligation to consider the government's energy objectives, and in particular with those objectives that call for the Commission to "encourage BC Hydro to reduce GHG emissions" and to "encourage BC Hydro to produce, generate and acquire electricity from clean or renewable resources," as well as with respect to certain aspects of BC Hydro's DSM proposals, a number of policy and legislative initiatives are relevant. BC Hydro submits that there are four BC Government and one Canadian Government legislative developments that affect:

- the financial risks associated with greenhouse gas ("GHG") regulatory actions in respect of natural gas based electricity generation in comparison with clean, renewable generation;
- the potential for increased use of electricity in applications traditionally reliant on fossil fuels as an energy source; and,
- the advisability of BC Hydro encouraging the use of high efficiency natural gas appliances for residential and commercial space and water heating as part of its DSM measures.

(BC Hydro Argument, p. 39)

The five relevant Canadian legislative initiatives are:

1. The January 1, 2008 *BC Greenhouse Gas Reduction Targets Act (GGRTA*), which, in conjunction with a Ministerial Order of November 25, 2008, sets into law target reductions from 2007 GHG emission levels of:

- six percent by 2012,
- eighteen percent by 2016,
- thirty three percent by 2020, and
- eighty percent by 2050

2. The May 29, 2008 *BC Greenhouse Gas Reduction (Cap and Trade) Act* ("*GHG Cap and Trade Act"*), which relates to BC's participation in the Western Climate Initiative ("WCI"), a partnership of seven US states and three Canadian provinces, and is to enable the reductions of GHG emissions through an as-yet-to-be developed cap-and-trade system. Although it has received Royal Assent, the GHG Cap and Trade Act comes into force by regulation which, at the time of this Decision had yet to be proclaimed.

3. The May 29, 2008 *BC Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act, 2008* ("*Emission Standards Act"*), section 2 of which comes into force by regulation and, amends the principal BC environmental statute – the *Environmental Management Act* ("*EMA*"). The *Emission Standards Act*, among other things, provides that:

    - prescribed coal-fired generators will be required to capture and sequester GHG emissions;
    - new electricity generation facilities, and prescribed expansions to existing facilities that use fossil fuels other than coal must, as soon as the *Emission Standards Act* comes into force, use "offsets" to bring their GHG emissions to "net-zero"; and
    - existing facilities that use fossil fuels other than coal will be given until 2016 to become net-zero with respect to GHG emissions.

GHG Offsets for the purposes of the *Emission Standards Act* have not been enacted under that Act as of the time of this Decision. The only legislative reference to GHG Offsets is OIC 905/2008, enacted December 8, 2008 pursuant to the *GGRTA*, which sets out the requirements for eligible GHG offsets for the purposes of fulfilling the BC Government's commitment to a carbon-neutral public sector by 2010.

4. The May 29, 2008 *BC Carbon Tax Act* applies to virtually all fossil fuels within BC including natural gas, coal, diesel fuel, gasoline, propane, and home heating oil, and specifically applies to the use of those fuels for the purpose of electricity generation.

Pursuant to section 84 of the *BC Carbon Tax Act*, the BC Cabinet may, with respect to a fuel or combustible that is the source of GHG emissions, provide for a regulation that exempts from the payment of the tax, or that refunds all or part of the tax paid subject to compliance obligations under the *BC Carbon Tax Act* and the new offset requirements for electricity generation under the *Emission Standards Act*. As of the time of this Decision, no such regulations have been enacted.

5. The Canadian Government has announced GHG emissions targets which have not been legislated as of the time of this Decision, but may be enacted through regulations under the *Canadian Environmental Protection Act*. The announced targets consist of absolute reductions with reference to 2006 levels of GHG emissions of:

    - twenty percent by 2020; and
    - fifty percent by 2060.

As well, the Canadian Government's "Turning the Corner" framework contemplated "intensity based" GHG reduction targets for regulated industries such as electricity generation of:

- eighteen percent by 2010; and
- a two percent continuous improvement annually thereafter.

In addition to the GHG emission legislative initiatives described above, references to the BC Government's Climate Action Plan of June 26, 2008, and the activities of its advisory Climate Action Team ("CAT") arose during the course of the proceeding.

Lastly, the policy context within which the Commission is to review the 2008 LTAP has been expanded by two February 18, 2009 decisions of the BC Court of Appeal concerning the Commission's obligation to consider the adequacy of consultation with First Nations.

1. In *Carrier Sekani Tribal Council v. British Columbia (Utilities Commission), 2009 BCCA 67 ("Carrier Sekani Decision")*, the Court determined that the Commission erred by failing to give an adequate opportunity to the Tribal Council to lead evidence and make argument with respect to the adequacy of consultation that had occurred with respect to the Energy Purchase Agreement ("EPA") between Alcan Inc. and BC Hydro when that matter was

before the Commission for review pursuant to section 71(1) of the *Act* in 2007.

2. In *Kwikwetlem First Nation v. British Columbia (Utilities Commission), 2009 BCCA 68 ("Kwikwetlem Decision")*, the Court found that the decision of the Commission to not consider the adequacy of Crown Consultation during its review of the Inland - Lower Mainland Transmission Reinforcement Project ("ILM" or "5L83") should be reconsidered, as the Commission's reliance on the environmental assessment process to ensure the adequacy of that consultation was incorrect (BC Hydro Argument, pp. 72-73).

The above policy and regulatory matters are referenced where relevant to the matters described and determined later in this Decision.

1.3 Conduct of the Hearing

1.3.1 Evidentiary Record

At the commencement of the Oral Hearing, the record included three rounds of IRs and responses thereto, the Direct Evidence of BC Hydro's four witness panels (Exhibits B-13 and B-13-1), and Intervenor evidence and IR responses thereto (if any) as filed by:

- Vanport Sterilizers ("Vanport") (Exhibits C5-3 and C5-5);
- Canadian Office and Professional Employees Union Local 378 ("COPE") (Exhibit C16-6);
- IPPBC (Exhibit C-17-5);
- BC Sustainable Energy Association and Sierra Club of Canada BC Chapter ("BCSEA") (Exhibits C21-4, C21-10 and C21-11); and
- Texada Action Now Community Association ("TAN") (Exhibit C33-3).

Among the many filings made during the course of the Oral Hearing, a number of exhibits were entered which expanded the policy framework described at Section 1.2 above. These included:

- BC Hydro's 2009 Bioenergy Call Phase 1 Request for Proposals Report (Exhibit B-15);
- BC Hydro's Service Plan for F 2010 (Exhibit B-16);
- BC Hydro's Letter of Shareholder Expectations (Exhibit B-17);

- Comments on the BC Government's Climate Action Team Report (Exhibit B-36);
- the Province of British Columbia's Strategic Plan (Exhibit C13-6);
- the Speech from the Throne opening the 2009 legislative session (Exhibit C-17-8); and
- the Western Climate Initiative Plan (Exhibits A-2-4, and C-17-19).

1.3.2 Issues List

Following receipt of submissions from the parties, by Order G-126-08 dated September 11, 2008 (Exhibit A-4) the Commission Panel determined that it would not publish an Issues List.

1.3.3 Commencement of the Oral Hearing

The Oral Hearing commenced on February 19, 2009. BC Hydro and TAN tabled written opening statements (Exhibits B-14 and C33-6 respectively). As well, BC Hydro and several Intervenors made opening statements which, in part, referred to the overall nature of the review and the current context. These aspects are summarized as follows:

- BC Hydro made extensive submissions with respect to the policy and regulatory framework, as summarized at Section 1.2 above, and its views as to the scope of the Commission's discretion in reviewing the Application. As well, BC Hydro introduced the purpose, chairperson, and participants of each of its witness panels.
- Three Terasen utilities – Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively "Terasen") made reference to the 2007 Energy Plan's policy of using the "right fuel for the right activity at the right time," and provided Terasen's views as to the importance of BC Hydro taking cost-effective measures to encourage potential space and water heating customers to adopt another, more efficient fuel, such as natural gas, for those avoidable electric loads (T3:161-62).
- Terasen further noted its views as to how taking such action would be consistent with the policy framework and regulations in terms of achieving the LTAP load/demand balance and GHG objectives, noting that the legislated obligation on the Commission is "to encourage public utilities to reduce [GHG] emissions, and "[t]hat legislated objective is not qualified by reference to provincial GHGs or the Province's GHG scorecard, although the government could have done that" (T3:172-74).
- The Joint Industry Electricity Steering Council ("JIESC") referenced the deteriorated state of the important forest-based industrial sector and the continuing uncertain and volatile

economic climate, and questioned the rationale for any locking-in on large, long-term resource acquisitions in an attempt to resolve gaps or to provide insurance 20 years out into the future, and submitted that BC Hydro should be only acquiring resources that are clearly necessary and that are cost-effective. JIESC provided its view that "cost-effective means the lowest long-term cost consistent with government policy as set out in the Energy Plan, the *[Act]*, and the Regulations thereunder," and that those instruments should be given more weight than other government policy pronouncements where such exist (T3:179-80).

- JIESC registered particular concerns with the LTAP's contemplation of an increase in BC Hydro's 2008 Clean Power Call ("CPC") from 3,000 to 5,000 GWh/year at $110-120/MWh in the context of untapped DSM availability at $40-50/MWh, and the replacement of up to 3,000 GWh/year of Burrard Thermal Generating Station's ("Burrard") generating capability, noting the forecast market price of electricity of $60/MWh and/or the cost of generation at Burrard at current natural gas prices as both being materially below the cost of electricity contemplated for the CPC (T3:183-87).
- The BC Old Age Pensioners' Organization *et al*. ("BCOAPO") echoed JIESC's concerns in respect of the unfavorable economic climate and noted that this was "the worst of times to consider locking BC Hydro into long-term electricity supply.", particularly from "scattered resources" given the Commission's pending inquiry under the new subsection 5(4) of the *Act* to investigate proactive strategic approaches that integrate the development of generation and transmission resources (T3:190-92).
- BCOAPO also commented as to the particular weight that should be given by the Commission in exercising its discretion on the policy matters that have been "hard wired in legislation or regulation," in contrast to those that remain at the policy level only, noting in particular its concurrence with BC Hydro's position that "where cost effective DSM can be used to avoid new energy acquisitions, the Commission must choose DSM over those acquisitions" (T3:194-95).
- IPPBC encouraged the Commission to look beyond the current unstable economic climate, and focus on the long term, with particular emphasis on the requirements of SD 10 in respect of self-sufficiency and insurance, noting the certainty, and long-term nature of the supply options presented by its members in response to BC Hydro's 2008 CPC (T3:198-99).
- The Commercial Energy Consumers of BC ("CEC") also noted the continuing dynamic and challenging nature of the economic environment and the difficulties that presented in long term forecasting of demand, emphasizing the need for the Commission to look to create flexibility to cope with those circumstances in its Decision. In particular, CEC pointed to the need to ensure that Burrard was effectively deployed for planning purposes to avoid the cost of new supply, and similarly, that "all cost-effective DSM" was in fact encompassed by BC Hydro's Application (T3:205-06).
- BCSEA emphasized the important role of DSM in the review process, and the need to ensure that in fact the Application did indeed encompass all cost effective measures. As well, BCSEA noted the complex interactions with GHG legislation and the other technical matters concerning Terasen's submissions in respect of the potential benefits of the selection of natural gas in lieu of electricity for seasonal applications (T3:214-16).

- Energy Solutions for Vancouver Island Society, *et al* ("ESVI") submitted that DSM directed to improving energy efficiency would provide the least expensive energy with low risk and make a positive contribution to mitigating environmental and GHG concerns, as well as lowering peak demand (T3:262).
- The Peace Valley Environmental Association ("PVEA") noted that its clear focus in the proceeding was on the proposed role of Site C, and the reasonableness of the expenses the Commission is being asked to approve for Stage 2 of the Site C evaluation process (T3:229).
- COPE, with reference to the evidentiary record of the Commission's review of BC Hydro's F2009/F2010 Revenue Requirements Application ("F09/F10 RRA"), submitted that the single most important factor escalating BC Hydro's rates was the cost of energy, and that one of the largest elements contributing to that increase was the realization of BC Hydro's commitments to purchase new high-cost supply through mechanisms such as the F2006 Call. COPE recorded its concern that the LTAP as proposed by BC Hydro would exacerbate this situation through additional commitments to such high cost supplies of energy, and its position that the downgrading of Burrard by 3,000 GWh/year for planning purposes was unwarranted (T3:233-36).

1.3.4 Witness Panels

BC Hydro provided four witness panels for cross-examination each chaired by a senior executive or manager of BC Hydro.

The Intervenors who provided witness panels for cross-examination were IPPBC, BCSEA and COPE.

1.3.5 Closure of the Record of the Proceeding, March 12, 2009

There was agreement among the parties that all outstanding undertakings would be filed by March 27, 2009.

The schedule for Final Argument was established as:

- BC Hydro by April 9, 2009
- Intervenors by April 24, 2009 (later amended to April 27, 2009 by agreement)
- BC Hydro Reply by May 7, 2009 (later amended to May 13, 2009 by agreement)

An Oral Phase of Argument, if required, was scheduled for May 21, 2009 (later amended to June 1, 2009 by agreement).

On motion from Commission Counsel, subject to the filing of outstanding undertakings, the Commission Panel Chair declared the evidentiary record closed on March 12, 2009.

1.3.7 Commission Panel List of Matters for Argument

By letter dated April 2, 2009, the Commission Panel provided the parties with a listing of matters where the Commission Panel believed that its determinations could be helpfully informed by submissions from the parties in argument (Exhibit A-21).

1.3.8 Oral Phase of Argument

By letter dated May 25, 2009, the Commission Panel advised the parties that it required an Oral Phase of Argument, and provided a list of matters on which it invited submissions (Exhibit A-20). This took place as scheduled on June 1, 2009.

The submissions made by the parties are reflected, where appropriate, in later Sections of this Decision. The Commission Panel appreciates the constructive contributions of the parties to its better understanding of the parties' positions on the matters before it.

2.0 JURISDICTIONAL MATTERS

2.1 Scope of Commission's Review

As described in Section 1.2 above, the Commission's scope of and criteria for review of a public utility's LTAP, and any included expenditure schedules, are relatively well defined by the *Act*, M271 and by SD 10. In essence, the Commission must accept an LTAP if the Commission determines that the carrying out of the plan would be in the public interest, or reject the LTAP either in whole or in part. The Commission may not amend or otherwise approve anything different than what has been applied for.

Similar provisions apply to expenditure schedules filed with the Commission.

Given the absence of specificity in the statutory framework as to what constitutes a "part" of an LTAP or accompanying expenditure schedule, the Commission Panel canvassed the parties as to their views on that matter in their arguments, as well as the implications of the regulatory parameters for assessing cost-effectiveness with the "parts" of a DSM expenditure schedule.

In their written arguments, and, tangentially, in the Oral Argument Phase, there was general agreement among the parties that the Commission could, with reason, reject any particular element or elements of the LTAP as applied for, and that it then became a matter of judgment as to whether the remaining elements constituted an "approvable" LTAP. The parties further were in general agreement that it was appropriate for the Commission Panel in its Decision to advise or otherwise suggest to BC Hydro what changes or other amendments could be made to any rejected parts, or if applicable, the whole of the LTAP so as to enable approval by the Commission should BC Hydro elect to resubmit its LTAP in whole or in part as contemplated by the *Act*.

The Commission Panel has proceeded accordingly in its review and in reaching its determinations.

2.2 Other Matters

Certain other jurisdictional matters arose in the course in the course of parties’ final submissions and, as necessary, are dealt with in the applicable Sections of this Decision.

3.0 APPLICATION AND ORDERS SOUGHT

In its Argument, BC Hydro summarized the purpose of the LTAP as being to "identify sufficient resources to reliably serve the growing demand for electricity within the BC Hydro service area, and to inform and guide [its] resource acquisition processes over the first ten years of the 20-year 2008 LTAP study horizon." In general terms, no Intervenor took issue with that statement of purpose (BC Hydro Argument p. 4).

BC Hydro also summarized the relief requested and the Order sought, as amended from its original Application by events during the proceeding, as follows:

A. Primary Relief #1: a Commission Order pursuant to subsection 44.1(6) (a) of the *Act* that the 2008 LTAP is in the public interest.

B. Primary Relief #2: a Commission Order pursuant to subsection 44.2(3) (a) of the *Act* that the following seven expenditures (referred to as Primary Relief #2, (a) to (g)) are in the public interest:

    (a) $418.0 million to be spent over F2009, F2010, and F2011 for the implementation of the DSM plan;

    (b) $600,000 to be spent over F2009 and F2010 to undertake and complete definition phase work for capacity-related DSM;

    (c) $1.6 million to be spent in F2010 for sustaining capital to ensure the reliability of Burrard;

    (d) $30.0 million to be spent over F2009, F2010, and F2011 to undertake and complete the definition phase work for Mica Units 5 and 6.

    (e) $41.0 million to be spent over F2009 and F2010 to undertake and complete the Site C Stage 2 definition and consultation phase work;

    (f) $2.0 million to be spent over F 2009 and F2010 to complete the definition phase work, and to implement the Clean Power Call; and

    (g) $140.1 million to be spent over F2009 through F2012 to complete the definition phase work for, and implement the Fort Nelson Gas Generating Unit project case #3 ("FNU3").

C. Primary Relief #3: approval of the Contingency Resource Plans ("CRP") for inclusion in BC Hydro's Network Integrated Transmission Services update to the BC Transmission Corporation ("BCTC") pursuant to the Commission's Directive 3 of Order G-58-05 *In the Matter of British Columbia Transmission Corporation: Application for an Open Access Transmission Tariff* Decision dated June 20, 2005 ("2005 OATT Decision").

D. Endorsements:

In its Argument BC Hydro explained that the basis for its requesting "endorsements" of certain of its proposals by the Commission was "to give parties clarity and BC Hydro direction by declaring that a treatment shall be presumed unless there is good reason for another treatment.", and further, that "[an] endorsement would create presumption in favor of [such a treatment which] could be set aside by the Commission in the future based on a clear case showing changed circumstances or appropriateness" (BC Hydro Argument p.8).

By way of specific example, BC Hydro cited its purpose for requesting endorsement of its targets for the energy to be supplied by Independent Power Producers ("IPPs") in response to the 2008 CPC as being to "establish the need as being made out, thereby focusing the section 71 filing...on the cost effectiveness of the Energy Purchase Agreements ("EPAs") awarded by BC Hydro to fill the target" (BC Hydro Argument p. 9).

While there was considerable contention in respect of the substance of some of the endorsements requested by BC Hydro, no Intervenor took issue with the principle of endorsement by the Commission as described and requested by BC Hydro. The eight specific endorsements requested by BC Hydro (referred to as Endorsements (i) to (viii) are:

(i) a proposed Clean Power Call pre-attrition target of 3,000 GWh/year or post-attrition target of 2,100 GWh/year;

(ii) the Clean Power Call clean or renewable eligibility requirement;

(iii) BC Hydro's plan to rely on Burrard for 900 MW of dependable capacity and 3,000 GWh/year of firm energy;

(iv) the DSM amortization period remain at 10 years;

(v) the filing of DSM performance reports on an annual as opposed to a semi-annual basis;

(vi) the elimination of the F05/F06 RRA Decision Directives 62 and 64, which relate to Load Displacement ("LD") projects being considered as supply side initiatives in light of the new definition of DSM in section 1 of the *Act*;

(vii) the amendment of F05/F06 RRA Decision Directive 60 to read as follows: "seek approval for all new Power Smart programs with a Total Resource Cost ("TRC") benefit/cost ratio of less than 1.0"; and

(viii) the continuation of BC Hydro's current capital plan review process.

(BC Hydro Argument, pp. 6-7)

The above matters are described and reviewed later in this Decision, as are both further matters of incidental relief requested by BC Hydro and particular relief sought by the Intervenors.

BC Hydro's request for an early determination of Mica 5/6 is reflected in Order G-69-09 and its accompanying Reasons for Decision dated June 8, 2009, and is not dealt with further in this Decision.

BC Hydro's request for an early determination of FNU3 is reflected in Order G-75-09 and its accompanying Reasons for Decision dated June 15, 2009, and is not dealt with further in this Decision.

4.0 STAKEHOLDER INVOLVEMENT, PUBLIC ENGAGEMENT AND FIRST NATIONS CONSULTATION

BC Hydro describes its engagement and consultation processes in the course of preparing its 2008 LTAP in part at Appendix Q to Exhibit B-1-1. The aspects covered included the LTAP itself, and separately, the Fort Nelson 2008 Resource Plan, the 2008 CPC, and Mica 5/6. LTAP processes included a Resource Options Update ("ROU"), Intervenor Workshops and public communications. The ROU engagement included a scoping session, meetings (both one-on-one and group), and a results session.

BC Hydro reports that participants "indicated satisfaction with the process," with interest being expressed to fully update the ROU inventory and characteristics, and to include a broader range of stakeholders and First Nations within the process. Two workshops were held, one covering impacts analysis, and the other reviewing drafts of the applications. These reviews gave rise to five sets of written comments which BC Hydro states were considered, and resulted in adjustments being made to its Application. As well, information was posted on BC Hydro's website and an "Energy Planning" newsletter provided to 65 First Nations groups and 590 interested parties and/or participants in the 2006 IEP/LTAP.

In terms of the 2008 CPC, BC Hydro reports that it convened a series of sessions with IPPs, First Nations, and other interested parties. It received 40 submissions, including some 600 comments on its draft Term Sheets which it considered in establishing its request for expressions of interest.

BC Hydro states that it reduced the "scale" of its 2008 LTAP application from that of the 2006 IEP/LTAP by targeting the 2007 Energy Plan and the relevant directions to the Commission, and focusing on interactions with the Registered Intervenors over the period July to December 2007. The business-focused ratepayer representative Intervenors (CEC and JIESC) were "carved out of the broader scoping forums due to scheduling considerations." Intervenor workshops with additional First Nations representation were convened over the period November 2007 to May 2008. Four sessions were held to review the Application at various stages, and to consider the range of estimates for 2008 CPC potential commitments.

BC Hydro reports separately on its DSM related consultation and engagement initiatives at Sub-Appendix A to Appendix K of Exhibit B-1-1, describing the “four avenues” of its approach as:

- a Conservation Potential Review (“CPR”) External Review Panel;
- an Energy Conservation and Efficiency (“ECE”) Advisory Committee;
- a Rates Working Group; and
- program workshops.

BC Hydro states that the CPR External Review Panel participated throughout the CPR process and the LTAP consultations. In particular it reviewed the scope of the CPR study, its terms of reference, the consultants engaged by BC Hydro, and similar matters. Its membership included Registered Intervenors, and representatives of other BC utilities, non-government organizations, and First Nations.

BC Hydro describes the ECE Advisory Committee as being formed pursuant to BC Hydro’s 2005 REAP negotiated settlement agreement, to provide advice to BC Hydro on achieving its long term goal “to develop and foster a conservation culture in BC that leads to customers choosing a dramatic and permanent reduction in electricity intensity.” It has a membership of 23, representing a diversity of First Nation and stakeholder perspectives and experiences. The Rates Working Group was created by the ECE Advisory Committee to focus on advice to BC Hydro as to how rates could be used to drive conservation and efficiency. It has fifteen members drawn from the ECE Advisory Committee, other Stakeholder Engagement initiatives and the general public, with one BC Hydro representative.

While BC Hydro’s consultation and engagement activities in respect of certain specific initiatives became a matter of contention in the proceeding, no Intervenor took issue with BC Hydro’s overall engagement and consultation program as outlined above. Contentious matters concerning BC Hydro’s consultation and engagement activities included:

- all ECE Advisory Committee recommendations in respect of Codes and Standards were accepted by BC Hydro, except for item 8.h) which advocated fuel-neutral codes and standards that favoured neither electricity nor natural gas. BC Hydro's CEO advised the ECE Advisory Committee that BC Hydro would require (and await) government guidance in this regard (Exhibit B-1-1 Appendix K p.93 of 213). This matter became prominent in the proceeding in respect of the appropriate role, if any, of DSM initiatives in influencing the selection of electricity or natural gas for space and water heating applications, which is dealt with at Section 7.7.7 of this Decision;
- IPPBC submitted that BC Hydro's canvas of its existing and potential new customers in the oil and gas sector was inadequate as to their plans for electrification of existing and new compression drives, and contrasted that level of consultation with that extended to the forest industry (IPPBC Argument p. 18). This matter, and other concerns raised by IPPBC, is dealt with at Section 6.3 of this Decision;
- PVEA registered concerns about "the utility of the consultative process carried out by BC Hydro in Stages 1 and 2 [of BC Hydro's evaluation of Site C]" (PVEA Argument, para. 5-8). These matters are dealt with at Section 7.2 of this Decision; and
- COPE raised concerns with respect to the adequacy of BC Hydro's engagement and consultative processes in respect of its application to reduce reliance on Burrard by 3,000 GWh/year for planning purposes noting that "By BC Hydro's own admission it has taken no steps to proactively deal with any misconception on the part of the public, the regulators or other stakeholders." (COPE Argument, p.21). These matters are dealt with at Section 6.5 of this Decision.

With respect to the broader issue of the Commission's obligation to inquire into the adequacy of BC Hydro's consultation and, if appropriate, accommodation of the interests of First Nations affected by its proposals as described at Section 1.2 above, no Intervenor took issue with the generality of BC Hydro's approach in that regard. Where these matters are of direct and immediate relevance, such as in the matters of the proposed Fort Nelson Generation Expansion, and the study authorizations for Mica 5/6 and for Site C, they are dealt with in those specific determinations or Orders of the Commission Panel.

5.0 MARKET CONTEXT AND ANALYSIS

BC Hydro assesses future market conditions for natural gas prices, electricity prices, GHG offset prices, and renewable energy credits (“REC”) in Chapter 4 of its Application.

5.1 Natural Gas and Electricity Price Forecasts

BC Hydro submits that the “long-term forecasts of natural gas and, by inference market prices for electricity, are based on long term central tendencies in prices. Prices in the forecast scenarios are sustainable in the mid to long-term” (BC Hydro Argument, p. 96). No Intervenor takes exception to this position. CEC agrees with the evidence filed by BC Hydro that the “long term forecast of natural gas and by inference market prices for electricity are reasonable for long term acquisition planning purposes” (CEC Argument, p. 22).

Only one Intervenor, IPPBC, advocates the rejection of BC Hydro’s natural gas price forecast (IPPBC Argument, p. 44).

In summary, IPPBC states that BC Hydro is “basing its Application on the Base Case price of natural gas growing at 1.5% in the Base Case” and “the probability of its high case natural gas pricing occurring, 53%, is greater than its base case, 44%” (IPPBC Argument p. 42). Because of the concerns it identifies, IPPBC believes that BC Hydro’s high case should serve as its base case (IPPBC Argument, p. 44).

BC Hydro responds that it has not relied only on the base case for its natural gas price forecast. Rather it has “used all three gas price scenarios (high, medium, and low) with the independent third party expert-assessed probability weightings” as the basis for its forecasts (BC Hydro Reply, p. 47).

Terasen observes that "All of the gas price forecasts provided by BC Hydro (except that of its own internally developed high gas price forecast and internally developed weighted average) reside below or in the lower part of [the sustainable long-term gas price] range until 2020" (Terasen Argument, p. 40). However, it makes no observations for the Commission to accept or reject the natural gas price forecasts. BC Hydro counters that Terasen's submission is inaccurate; all natural gas price forecasts in the 2008 LTAP were developed by its independent advisor, Global Energy, including the weighting factors for the natural gas price scenarios (BC Hydro Reply, p. 48).

5.2 Greenhouse Gas Price Forecasts

BC Hydro recognizes that the BC and federal governments, along with several US Western Electricity Coordinating Council ("WECC") jurisdictions have established GHG reduction targets which have altered the risk profile of certain supply options including natural gas fired generation. There is considerable uncertainty associated with forecasting GHG prices. BC Hydro has adopted a policy scenario approach to assess the impact of GHG regulation and GHG offset price variability. It has relied on an independent consultant, Natsource, to develop GHG scenarios and price forecasts.

Most Intervenors were silent with respect to the GHG price forecast. However, both CEC and BCSEA concur with BC Hydro's policy scenario approach and submit that the GHG price forecast should be accepted for the 2008 LTAP purposes (CEC Argument, p. 22; BCSEA Argument, pp. 29, 30).

IPPBC filed the evidence of Dr. Mark Jaccard which includes a GHG price forecast, and concludes that the Commission "should reject BCH's GHG price forecast" (IPPBC Argument, p. 49).

BC Hydro identified certain limitations in the evidence filed by IPPBC and observed that "IPPBC's expert, Dr. Jaccard, did not reject the Natsource analysis, noting that IPPBC admitted he "has not studied BC Hydro's [GHG] price scenarios and sensitivity analysis" (BC Hydro Reply, p. 49).

5.3 The Market for Renewable Energy Credits

BC Hydro submits that there is a market for RECs, but notes that the market is evolving and uncertain. It concludes that the "REC price analysis was intended to provide a directional indication of REC impacts on resource reliance and selection, and did not impact the underlying conclusions of the analysis" (BC Hydro Argument, p. 107). CEC concurs "that RECs will have potential to add value to any sale of renewable energy, however a great deal of uncertainty remains" (CEC Argument, p. 24).

IPPBC acknowledges that the market for RECs is a relatively new phenomenon. However, it posits that there is not "as much uncertainty as some Intervenors were postulating through cross examination." IPPBC suggests that, if BC Hydro uses the mid-case for its natural gas price forecast, it should use the mid-range for its REC forecast.

IPPBC also suggests that if the RECs can be sold by BC Hydro the revenue therefrom should be taken into account when evaluating IPP bid prices in the 2008 CPC. (IPPBC Argument, p. 45)

BC Hydro does not address this issue in its Reply.

Commission Determination

The issue of the treatment of revenue from RECs in any economic analysis prepared by BC Hydro of supply side options was not canvassed adequately in the proceedings and the Commission Panel makes no finding on it. **The Commission Panel accepts the price forecasts for natural gas, electricity, GHGs, and RECs for purposes of the 2008 LTAP.**

6.0 LONG TERM ACQUISITION PLAN

6.1 Introduction

This Section deals with Primary Relief #1 sought by BC Hydro, namely "a Commission Order pursuant to subsection 44.1(6) (a) of the *Act* that the 2008 LTAP is in the public interest."

The Section first reviews BC Hydro's plan to comply with the requirements of SD 10 as they relate to BC Hydro achieving energy and capacity self-sufficiency. Secondly it reviews BC Hydro's mid-load forecast, and its demand side management initiatives to determine its electricity supply obligations for the plan period before and after the requirement to exceed those obligations. Thirdly it reviews BC Hydro's existing and committed resources throughout the plan period to determine the gap between the electricity supply obligations and the existing and committed resources. Lastly it reviews the resources that BC Hydro proposes to acquire to fill this gap.

Throughout this Section the Commission Panel references four years data out of the 20 years in BC Hydro's LTAP: F2012, F2017, F2022 and F2027. F2012 is the first "non-operational" year of BC Hydro's plan period, F2017 and F2027 are fiscal years proximate to 2016 and 2026 dates prescribed in section 3 of SD 10, and F2022 is the mid-point between the latter two dates.

In the Section on DSM, the Commission Panel also considers F2020, as BC Hydro uses that date as a reference point to measure its compliance with the *Act* and the 2007 Energy Plan.

6.2 Energy and Capacity Self-Sufficiency

In this Section the Commission Panel reviews the implications of section 3 of SD 10 and the 2007 Energy Plan on the 2008 LTAP, which deal with energy and capacity self-sufficiency as was described at Section 1.2 of this Decision.

It reviews the submissions it received from parties as to the extent that the Commission Panel should use the 2007 Energy Plan as a contextual aid in interpreting SD 10. It also reviews the meaning of "capable" or capability in SD 10. Finally, it reviews the two elements of the self-sufficiency criterion, one to meet and the other to exceed by 3,000 GWh/year, BC Hydro's electricity supply obligations.

6.2.1 The 2007 Energy Plan

The 2007 Energy Plan addresses self-sufficiency as follows:

"Achieve Electricity Self-Sufficiency by 2016

> Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.
>
> Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. <u>This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power</u>" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports" (emphasis added) (Exhibit B-1-1, Appendix B1, p. 13 of 84).

Policy Action 10 of the 2007 Energy Plan provides that:

"10. Ensure self-sufficiency to meet electricity needs, including 'insurance'

> The Province wants to ensure that British Columbia has the reliable made-in-BC supply it needs to meet the growing demand for electricity, and that new resource acquisition is planned in a way that recognizes the long lead time and implementation risks associated with new power projects, and the challenges of forecasting future needs. In particular, for BC Hydro, the Province wants to ensure that BC Hydro has enough BC-based power at all times, even in low water years, to

> meet its customers' electricity needs. Therefore, after implementing all cost-effective energy conservation opportunities, BC Hydro will acquire sufficient BC-based resources by 2016 so that BC Hydro can meet its customers' needs even under critical water conditions. By 2026, BC Hydro will acquire 3,000 gigawatt hours of supply on top of their firm energy requirements (the energy required to meet customer needs under critical water conditions) and capacity resources needed to effectively integrate this energy in a cost-effective manner. The Province recognises the ongoing importance of trade for maximising the value of BC Hydro's heritage resources and for optimising its system and this activity will continue. The British Columbia Utilities Commission will continue to have responsibility for regulating BC Hydro, within the context of the self-sufficiency requirement" (Exhibit B-1-1, Appendix B1, p. 52 of 84).

6.2.2 Contextual Aid

Item 5 of the Commission Panel's agenda for the Oral Phase of Argument sought submissions with respect to the extent to which it should use the 2007 Energy Plan as a contextual aid in order to ensure that the 2008 LTAP complies with the direction given to the Commission by SD 10. Item 5 read as follows:

> "With respect to section 3 of SD 10, the Commission Panel wishes to hear further submissions on "self sufficiency," in particular with respect to the extent to which it should use the 2007 Energy Plan as a contextual aid in order to ensure that the 2008 LTAP complies with the direction given to the Commission by SD 10. Further, can the Commission Panel assume that the self-sufficiency requirement is a reliability criterion and that the need for 3,000 GWh/year "insurance" is a subset of the self-sufficiency requirement and is itself a reliability criterion? BC Hydro's evidence is that it has not considered the nature of the insurance or the timing of its acquisition (T12:2285). Should the Commission Panel accept an LTAP under these circumstances and if so, on what basis? Similarly, BC Hydro's existing and committed resources in its LTAP rely on Market Allowance until December 31, 2015. Does this reliance comply with SD 10?" (Exhibit A-20)

BC Hydro submitted that the 2007 Energy Plan "should be accorded significant weight." While noting that during the proceeding it had cited case law that concluded legislative history is not always a good indicator of "the intent of the government," it pointed out that the 2007 Energy Plan contained an opening message from both the Premier and the Minister of Energy, Mines and Petroleum Resources, which suggested "it's beyond dispute that the 2007 Energy Plan clearly reflects the intent of the BC government." Finally, BC Hydro submitted that the 2007 Energy Plan should be read in conjunction with the Shareholder's Letter of Expectations, and its President's testimony that the letter "obliges BC Hydro to undertake certain 2007 Energy Plan actions, including implementing policy action number 10 of the 2000 Energy Plan, which speaks to self-sufficiency"(T16:2932-33).

COPE was the only Intervenor to take issue with this submission and submitted that legislative history (such as the 2007 Energy Plan) only comes into play during the interpretation of statutory instruments like SD 10 if ambiguity exists in the language.

COPE submitted that "the self-sufficiency requirement embodied in Section 3...is clear and unambiguous" and that there is no need to have recourse to the 2007 Energy Plan "to figure out what it is that is meant. The 2007 Energy Plan and in particular the elements of it relating to self-sufficiency are policy directions. They're not binding" (T16:2970-71).

6.2.3 The Nature of the Self-Sufficiency Criterion

Item 5 of the Commission Panel's agenda for the Oral Phase of Argument also addressed whether the Commission Panel might consider that the self-sufficiency requirement is a reliability criterion.

BC Hydro submitted that this had been addressed in its Argument and that the self-sufficiency requirement was indeed a reliability criterion (T16:2932).

No Intervenor took a contrary position.

6.2.4 Capability

Section 3 of SD 10 obliges the Commission in regulating BC Hydro to use the criterion that BC Hydro is to achieve energy and capacity self-sufficiency by "becoming capable of" (emphasis added). Neither "capable" nor the frequently used term "capability" is defined in either of SD 10 or the *Act*.

In testimony, BC Hydro offered that for its Heritage hydro assets, the 42,600 GWh/year specified aggregate for those assets in a critical year constituted their capability. For its thermal assets, particularly Burrard, BC Hydro noted a difference between "actual capability" and its "planned reliance" on the unit depending on other circumstances such as its technical condition (T8:1431-32).

Further, BC Hydro indicated that it did not generally employ statistical derived availability factors in its assignment of electricity supply capability levels to either its hydro or thermal assets, but looked to the design rated capacity of the driving turbine and the generator i.e. MW, and derived the generating capability in GWh by way of an "engineering exercise." Technical issues affecting the availability of the rated capacity would cause BC Hydro to reduce its rated reliance on the asset until the technical matters were resolved (T8:1434).

Pursuant to Item 4 of the Commission Panel's agenda for the Oral Phase of Argument, the Commission Panel sought submissions from the parties as to: what matters should it consider in determining the meaning of "capable" as used in section 3 of SD 10; whether it should consider the definition of capability from the glossary of terms in BC Hydro's 2004 IEP Application; and whether it should consider any other definitions or descriptions. The 2004 IEP defined "capability" as:

> "The quality to do a given task or to achieve a given target. In relation to the *integrated system* it refers to facilities that can be used under specified conditions for a given purpose. *Energy capability* is the amount of energy that can be generated under specific conditions by a *generating unit* or by the *electric system* over a period of time, typically expressed in GWh/year."

BC Hydro submits that the 2004 IEP definition was "very high level and is not sufficiently complete" and cited the Concise Oxford English Dictionary ("OED") definition of capable as "[h]aving the ability or quality necessary to do something." BC Hydro cites subsection 3 (d) of SD 10 - "[B]y becoming capable of meeting by 2016 and each year thereafter…" and argues that "each year thereafter" is "critical."

With reference to its responses to IRs, BC Hydro submits that “in order to be capable of meeting BC Hydro’s electricity supply obligations, first the facility must have the technical capability to meet BC Hydro’s electricity supply obligations and second, the facility must have the ability to be permitted or the ability to maintain its existing permits” (T16:2917-18). BC Hydro noted that its inclusion in the IR responses of a reference to “economic capability” was of lesser importance, as it was required for computer modeling simulation purposes.

JIESC, BCSEA, and ESVI generally support BC Hydro’s position in that “capable means physically capable” on an on-going basis (T16:2919).

IPPBC also cites the OED definition in support of its position that the definition in the 2004 IEP is insufficient, and argues that “technical or engineering, social and economic” factors have to be considered. It submits that a power plant capable of meeting the requirement of SD 10 “...has to be something that is a form of generation…in practical terms, not just in theory” (T16:2921).

CEC rejects a definition of capable that includes an economic test, submitting that “capable” in SD 10 has “the normal utility meaning” i.e., “the unit must have the physical, technical, and legal ability to provide.” CEC further submits that there is “no legislative direction to read economic into [capable] in SD 10” (T16:2926).

BCOAPO agrees with the first two aspects of BC Hydro’s definition, but concurs with CEC as to the inappropriateness of the inclusion of economic considerations in the definition. BCOAPO further submits that SD 10 “requires only that BC Hydro to be able to produce or procure the required levels of energy by certain dates, not that they must actually generate that energy, or that they are required to do so when it is uneconomic” (T16:2926).

COPE submits that the 2004 IEP definition is “precisely what is intended by the use of “capable,” in that “It speaks to the ability to generate energy over the course of the year, not whether or to what exten[t] that capability is actually used in any given circumstance.” COPE further submits that the

2004 IEP definition is wholly consistent with the OED definition of “capable,” and that if the government wanted to import a different definition from the ordinary meaning of capable, it would have made that manifest in SD 10” (T16:2929-2931).

BC Hydro made no submissions in reply.

6.2.5 Meeting the Electricity Supply Obligations

BC Hydro states that as a result of SD 10 it made two changes to the reliability criteria it used 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 its electricity supply obligations:

- it removed the 2,500 GWh/year non-firm/market allowance from the energy load/resource balances after 2015; and
- it removed the 400 MW market reliance from the capacity load/resource balances after 2015.

(Exhibit B-1, pp. 2-17/18)

BC Hydro states that the 2,500 GWh/year non-firm/market allowance consists of three components:

- Heritage hydro non-firm energy;
- imported non-firm energy; and
- domestic IPP non-firm energy.

SD 10 precludes capability reliance on Heritage hydro non-firm energy, and also provides that external markets cannot be relied upon after 2015 for purposes of meeting electricity supply obligations. BC Hydro notes it has now included domestic IPP non-firm energy in the load/resource balance pursuant to firm electric load carrying capability ("FELCC") studies (Exhibit B-1, p. 2-17).

BC Hydro addresses the test to be applied to the 2008 LTAP with respect to the SD 10 self-sufficiency requirement and submits that the test is whether BC Hydro, through the 2008 LTAP collective actions and plans, is capable of achieving self-sufficiency as defined by SD 10. BC Hydro further submits that determining whether BC Hydro through the 2008 LTAP is capable of achieving self-sufficiency does not require demonstrating that BC Hydro through the 2008 LTAP is 100 percent certain of achieving self-sufficiency.

BC Hydro notes that there will be at least one more LTAP filing before the 2016 self-sufficiency date, probably in 2011, at which time it will have a better understanding of the risks and requirements associated with delivering the required DSM and supply side options at that time. BC Hydro also anticipates that it will have the ability, prior to the 2016 self-sufficiency date, to adjust one or more of the following:

- the DSM Plan;
- acquisition plans and processes; and
- CRP projects such as Mica Units 5 and 6.

(Exhibit B-12, BCUC 3.262.1)

BC Hydro states that it reviewed the Evidentiary Update and "discovered there was a deficit in F2013 and F2014 after the updated LTAP action plans. This was a new and unexpected finding." BC Hydro submits that "the near term deficit will be managed and actions will be taken, however such near term actions can be managed within BC Hydro's standard procedures" (BC Hydro Argument, p. 175).

BC Hydro addresses the fact that the surplus at F2017 was reduced from 1,600 GWh in its original Application to 300 GWh in the Evidentiary Update and submits that "[g]iven the current economic uncertainty, economic hardship and potential for further delays in load growth, BC Hydro felt it was prudent to reduce the projected surplus in F2017 by being more conservative in the [2008 CPC] targeted volume while at the same time continuing to have a sufficiently large Call volume to attract larger and potentially cost-effective projects" (BC Hydro Argument, pp. 175-76).

COPE agrees with BC Hydro's assertion that determining whether BC Hydro is capable of achieving self-sufficiency does not require demonstrating that the actions set out in the 2008 LTAP will guarantee self-sufficiency with 100 percent certainty (COPE Argument, para. 55).

NaiKun Wind Development Inc. ("NaiKun") submits that BC Hydro's evidence on DSM and the premise upon which the success of the LTAP are based makes it apparent that BC Hydro's fallback position is to implement its CRP rather than acquire new energy supplies from IPPs in order to achieve electricity self-sufficiency by 2016 (NaiKun Argument, pp. 9-10).

As part of agenda item 5 for the Oral Phase of Argument, the Commission Panel posed the following question: "…BC Hydro's existing and committed resources in its LTAP rely on Market Allowance until December 31, 2015. Does this reliance comply with SD 10?"

BC Hydro submitted that it did indeed comply with SD 10 and that no party had submitted otherwise, concluding "there is clearly no need to remove the 2,500 gigawatt hour a year non-firm market reliance from the resource stack any earlier than BC Hydro has done, and indeed in BC Hydro's submission, to remove it earlier would be harmful to BC Hydro's customers" (T16:2936).

JIESC submitted that "the ability to rely on market energy in part is prudent, and it does help to moderate increases as we move to self-sufficiency. And again, those rate increases are very substantial" (T16:2946).

BCOAPO submitted that "[s]elf-sufficiency is required by the wording of this Special Direction by 2016, and it does not say anything about one year sooner or one day sooner, nor does it limit the resources that can be used in the meantime to serve load prior to that deadline date" (T16:2948).

6.2.6 Exceeding the Electricity Supply Obligations by 3,000 GWh/year

BC Hydro stated that the 3,000 GWh/year "insurance capability" required to be in place "as soon as practicable, but in any event no later than 2026" pursuant to SD 10, was included in its portfolio analysis as a requirement to be achieved by 2026, and (in its initial Application) had been ramped up by increments of 1,000 GWh/year in the years 2024 to 2026 (Exhibit B-3, BCUC 1.36.2).

It qualified this response by stating "this modeling was not intended to imply the plan as modeled would be the best or most appropriate plan for implementing the insurance" (Exhibit B-4, BCUC 2.187.2).

BC Hydro notes that the term "practicable" is not defined in section 1 of SD 10, and submits that interpreting the term "practicable" as that term is used in SD 10 should take into account:

- the plain, ordinary meaning of the term. Courts have, among other things, used dictionaries as a source of what the plain, ordinary meaning is of terms used in statutes and regulations; and
- the entire wording of subsection 3(e) of SD 10, which directs the BCUC, in regulating BC Hydro, to use the criterion that BC Hydro is to exceed, "as soon as practicable *but no later than 2026*, the electricity supply obligations by at least 3,000 gigawatt hours per year and by the capacity required to integrate that energy in the most cost-effective manner…" (Exhibit B-3, BCUC 1.43.1).

BC Hydro stated that the action items in the 2008 LTAP, such as DSM, the 2008 CPC, Site C, Burrard, Mica 5/6, and 5L83 were designed to meet its current and near term obligation including the first steps to self-sufficiency and that it will be in a better position to propose the succeeding steps in subsequent LTAPs (Exhibit B-3, BCUC 1.43.1). BC Hydro further stated that it considered it to be too early to determine the best manner to implement the insurance requirements of SD 10 (Exhibit B-4, BCUC 2.187.2).

BC Hydro testified that in a high-water year it could potentially have a surplus of 13,000 GWh while it currently only had the transmission capacity to export 10,000 GWh/year (T4:452), which was why it had chosen not to consider insurance until the three years leading up to 2026. BC Hydro testified. "We haven't to this point figured out exactly how we'd go about determining what cost-effective or practicable is. That's something that we wanted to get to a point of self-sufficiency first, and we haven't yet determined whether and if it made sense to advance that insurance premium (sic) earlier than fiscal 2026" (T12:2285), and "I think if the legislature had intended that insurance be used for that purpose (i.e. to mitigate problems caused by equipment failure or understated load forecasts), they'd have required us to have it by the year 2016, when we're required to be self-sufficient, rather than 2026, which is what was set out in Special Direction 10" (T12:2287).

In its Opening Statement, JIESC suggested that this was no time to be thinking about insurance since: "If BC Hydro were to purchase 3,000 gigawatt hours per year of insurance energy now instead of out in 2026, the project annual costs would be $110 times 3,000, or $330 million per year. By definition as insurance, it's energy that the BC Hydro customers will probably not require. If it's sold in the market at currently projected prices of $60, the annual net loss will be in the range of $150 million a year and it's going to be the customers that are going to bear that cost, not the IPPs, not the government" (T3:186-87).

NaiKun submits that BC Hydro has misinterpreted section 3(e) of SD 10 and the phrase "in the most cost-effective manner" as an absolute term within the definition of practicable (NaiKun Argument p. 7). NaiKun submits that "BC Hydro's aggressive position on DSM savings is contrasted by its relaxed position on meeting the insurance provisions of SD 10 which would serve to mitigate the DSM deliverability risk. It was common ground in the Application that a new generating project typically requires approximately seven years to be in service after a call process is initiated. If an IPP project was part of BC Hydro's fallback option, then in order for that IPP project to come on line in time to contribute towards achieving self-sufficiency, BC Hydro should secure such resources now" (NaiKun Argument, pp. 9-10).

NaiKun requests that the Commission endorse volumes in BC Hydro's 2008 CPC "to meet…post-attrition SD 10 insurance of 3,000 GWh/year assuming...an attrition rate of 50 % to 60 %" (NaiKun Argument, p. 1).

IPPBC agrees with NaiKun that BC Hydro has misinterpreted section 3(e) of SD 10 and submits that the word "cost-effective" specifically applies to capacity where BC Hydro is "required to integrate the energy in the most cost-effective manner." IPPBC also draws attention to BC Hydro's claim of a 13,000 GWh/year surplus in a high water year and observes that 3,000 GWh of such surplus would relate to Burrard, which would not be operated in a high water year, and submits that transmission is not a constraint to selling any surplus (IPPBC Argument, pp. 39-40). IPPBC addresses the definition of "practicable" and submits that it has been defined as "able to be effected, accomplished or done" and submits that the meeting and exceeding are not "courses or actions that have to be carried out in series and must be carried out in parallel" (IPPBC Argument, p. 42).

IPPBC submits that the "Commission should reject BC Hydro's interpretation of SD 10 in relation to insurance" (IPPBC Argument, p. 42).

BCOAPO describes itself as "generally skeptical of the value to ratepayers of such a significant overproduction or acquisition of energy" (BCOAPO Argument, p. 5). Similarly JIESC considers that "insurance supply is energy that BC Hydro and its customer will probably not require but must have available." JIESC supports BC Hydro's argument opposing any obligation on it to purchase all or part of 3,000 GWh/year of energy to meet the insurance requirements set out in SD 10 at this time (JIESC Argument, p. 10). JIESC calculates the annual net loss of insurance to be approximately $180 million per year and concludes that "[i]n customers' minds there is no good reason to take on such a risk, particularly at this time, for "insurance" that is not likely to be required until 2025, if ever" (JIESC Argument, pp. 17-18).

COPE agrees with BC Hydro that, while the "insurance" requirement is relevant in so far as the 2008 LTAP covers a period extending beyond 2026, it is too early to either (a) determine the best manner for implementing the insurance requirement; and/or (b) implement the insurance requirement at this time (COPE Argument, para. 53).

CEC suggests "beyond the 3,000 GWh/year of energy reliance [on Burrard] the remaining 3,000 GWh/year of [Burrard's] capability may adequately perform the role of providing insurance capability" (CEC Argument, p. 34).

BC Hydro, in Reply, submits that had the government meant practicable to mean "able to be effected" it would not have used the phrase "no later than 2026." In addition BC Hydro advocates a "cautious approach" to acquiring energy that its customers "will probably not require" and which will have to be sold into the export spot market. BC Hydro submits that the Section 5 Inquiry will provide additional information with respect to the export spot market and that "prematurely using the insurance in advance of such information would be imprudent" (BC Hydro Argument, pp. 17-18).

In its agenda for the Oral Phase of Argument, the Commission Panel posed the following question "BC Hydro's evidence is that it has not considered the nature of the insurance or the timing of its acquisition (T12:2285), should the Commission Panel accept an LTAP under these circumstances and if so, on what basis?"

BC Hydro submitted that the premise of the question was incorrect, and that it had considered the 3,000 GWh of insurance in sufficient detail to determine that "now is not the time to acquire that energy." In addition BC Hydro submitted that the "it has not been demonstrated that it is cost-effective now to use the 3,000 gigawatt hours a year as an insurance," nor has it been established whether the insurance should comprise independent power projects or Site C, "BC Hydro's self-build option" (T16:2935). In response to a question from the Commission Panel on the role Burrard might play in providing insurance, BC Hydro submitted "Our submission is if Burrard is not capable of running…at 6,000 gigawatt hours a year, it cannot fulfill the insurance requirement. It must be capable of doing that" (T16:2938).

CEC endorses "BC Hydro's delay in terms of acquisition of the insurance power" (T16:2943).

JIESC submits that BC Hydro and its customers "have been given a basically 15-year timeframe, maybe a little over that, in which to put the insurance component in place", and that it's also likely that, between now and 2026, there will be very major advances in clean energy production. JIESC submits that the necessary analysis needs to be done and that it is "perfectly appropriate to get started in the next LTAP" (T16:2945-46).

NaiKun submits that "an unqualified endorsement of the LTAP would mean that the Commission also endorses BC Hydro's plans of acquiring the insurance as – in F2027 as being the right answer." NaiKun further submits that the Commission should not reject the LTAP in its entirety as a result of BC Hydro's failure to adduce evidence on the insurance requirement of SD 10, or the timing of its acquisition. Rather, the Commission ought to reject those elements of the LTAP that are not consistent with the government's objectives of SD 10 and the energy plan (T16:2958-59).

IPPBC submits that it is "very concerned about the 2008 Clean Power Call, and whether that will survive any demise of the LTAP," and submitted that while "...BC Hydro doesn't have to have an immediate 3,000 hours of insurance… as soon as practicable has to be interpreted in its ordinary normal way. And it means what it says, it says what it means, and there should be some movement in that area and there simply isn't any movement in that area" (T16:2966).

Commission Determination

The Commission Panel notes that all parties, except COPE, agreed that it can use the 2007 Energy Plan as a contextual aid to ensure that the 2008 LTAP accords with the directions given to the Commission in SD 10. It also notes that all parties agreed that the self-sufficiency requirement of SD 10 is a reliability criterion.

The Commission Panel takes it as self-evident that the technical condition and legal and permitting status of BC Hydro's units enables their reliable operation, unless it has been specifically advised to the contrary by BC Hydro. Given the flexibility of dispatch and supply options that SD 10 permits BC Hydro and the Commission, the Commission Panel sees little, if any, role for economic considerations in determining a unit's generating capability for the purposes of SD 10 compliance.

Having considered the submissions from the parties, the Commission Panel finds that the definition of "capability" from the 2004 IEP is appropriate for the purposes of this LTAP. In other words, what a unit is capable of contributing to BC Hydro's electricity supply obligation is to be determined by its design capacity under specified conditions over a period of time, typically a year – the "engineering exercise" as described by BC Hydro, and referenced in Section 6.2.4 of this Decision.

For future LTAPs, the Commission Panel suggests that BC Hydro pay particular attention to circumstances where it has documentary evidence of pending long-term or otherwise irreversible permanent changes in the technical condition or legal and permitting status of its generating units, and bring those forward for approval or endorsement by the Commission in that proceeding.

When it considers the first part of the SD 10 criterion, namely self-sufficiency by 2016 and each year thereafter, the Commission Panel considers BC Hydro's reliance on a market allowance of 2,500 GWh/year up to 2015 to be acceptable. There is no qualifying phrase such as "as soon as practicable" and the Commission Panel agrees with BCOAPO that the legislation "does not limit the resources that can be used in the meantime prior to that deadline date."

When it considers the second part of the self-sufficiency criterion, being the obligation of "exceeding as soon as practicable but no later than 2026 the electricity supply obligations by at least 3,000 gigawatt hours per year," the Commission Panel finds that, using the 2007 Energy Plan as a contextual aid, the words at p. 10: "This means that over the next two decades, BC Hydro must acquire an additional supply of 'insurance power,'" serve to clarify the Government's intention as to the meaning of "as soon as practicable." The Commission Panel concludes the 2026 date is to be considered a "drop-dead" date and that the process of achieving self-sufficiency is intended to be an on-going process that should be planned in an on-going fashion rather than on a "just in time" basis.

The Commission Panel agrees with IPPBC that the word "practicable" has the meaning ascribed to it in Canadian case law as "able to be effected, accomplished or done" and that the words "cost-effective" in section 3 of SD 10 specifically apply only to capacity. The Commission Panel also agrees that the actions "of meeting and of exceeding" can take place in parallel rather than in series.

The Commission Panel notes BC Hydro's treatment for planning purposes of this part of the criterion was to increase the volume of future resources in or around F2025, to create a surplus of 3,000 GWh/year in F2027, as well as BC Hydro's testimony that it was "simply too early right now to consider taking actions to gather the insurance provision in SD 10." In the Commission Panel's view, BC Hydro has failed to recognize the 2007 Energy Plan reference to "the long lead time and implementation risks associated with new projects and the challenges of forecasting future needs," and accordingly has failed to adequately address the self-sufficiency obligation established by SD 10 in its 2008 LTAP.

In the Commission Panel's view, the 2007 Energy Plan envisages the 3,000 GWh/year exceedance as something that should be built-up over the "next two decades" i.e., over the years 2007 to 2026 rather than be put in place just prior to 2026.

Accordingly, the Commission Panel rejects that part of the 2008 LTAP that concerns energy and capacity self-sufficiency.

In its next LTAP, BC Hydro is requested to pay particular attention to the phasing in of the steps it deems necessary in order to meet the two aspects of self-sufficiency specified by SD 10. Particular regard should be given to achieving the requirements in a manner that meets the

requirement of having the capability "within the Province," while avoiding any undue burden on its ratepayers.

6.3 Load Forecast

This Section reviews BC Hydro's Load Forecast.

6.3.1 Background

The 2008 LTAP includes BC Hydro's 2007 Load Forecast, which was published in December 2007 and comprised the energy and peak demand forecast for BC Hydro's integrated system as well as its non-integrated areas ("NIA") which included the Fort Nelson region.

In the summer and fall of 2008 the global financial crisis led to deteriorating economic conditions that were having a material impact on the BC economy, and prompted BC Hydro to request and receive approval from the Commission to file an updated load forecast to be considered as part of its 2008 LTAP. BC Hydro filed its Evidentiary Update, which included its 2008 Load Forecast Update, on December 22, 2008 as Exhibit B-10. The 2008 Load Forecast was prepared using the same methodological approach as the 2007 Load Forecast, including a sector by sector analysis of load (Exhibit B-10, p.4).

BC Hydro states that the cut-off point for the new information in its 2008 Load Forecast Update was substantially mid to late October 2008. However, it did include customer-by-customer information current to December 2008 for industrial customers. It included "updated forecasts of the key economic drivers used in the load forecast models, revised industrial production forecasts and expectations for large industrial customers. [It] also contains updated forecasts of electricity rate changes and their impact on the load" (Exhibit B-10, p. 4).

The following table sets out the forecast by customer class for certain selected years of the forecast period:

2008 Load Forecast Update

GWh/year	F2012	F2017	F2022	F2027
Residential	18,485	19,998	21,514	23,246
Commercial	16,829	18,463	20,244	22,432
Industrial	19,158	20,678	20,278	20,363
Sales to Others	1,807	1,934	2,007	2,082
Line Losses	5,600	6,063	6,411	6,862
Total Gross Requirements	61,878	67,137	70,454	74,986
NIA	516	965	1,136	1,139
Integrated System	61,362	66,172	69,318	73,847
Integrated System Peak (MW)	11,279	11,989	12,398	13,239

(Source: Exhibit B-12, BCUC IR 3.250.1 – Table A3-6)

6.3.2 Methodology

BC Hydro states that both its 2007 and 2008 Load Forecasts were developed using substantially the same methodology used for the 2006 Load Forecast, which had been the subject of extensive review in the 2006 IEP/LTAP proceeding, and where the Commission had found that “BC Hydro’s Load Forecast has generally been prepared in accordance with the [BCUC’s] Guidelines and accepts that the results of the 20-year forecast are reasonable for purposes of the 2006 IEP/LTAP.”

BC Hydro states that its forecasts excluded the impact of any savings from incremental DSM initiatives, but, as directed by the Commission in the 2006 IEP/LTAP Decision, it did include the impact of forecasted future rate increases.

BC Hydro describes its three major customer classes as follows:

6.3.2.1 Residential

BC Hydro's residential sector currently consumes about 31 percent of its total annual billed sales, and the drivers of the residential forecast are the number of accounts and average annual use per account. Growth in the total number of accounts is driven by estimates of growth in housing starts.

6.3.2.2 Commercial

BC Hydro's commercial sector currently consumes about 29 percent of its total annual billed sales. BC Hydro states that, at an aggregate level, commercial consumption is closely tied with overall economic activity in the province, and that key drivers for the commercial sector include regional retail sales, regional employment and regional commercial output. As a result, future economic trends are good indicators of future electricity consumption in the commercial sector.

6.3.2.3 Industrial

BC Hydro's industrial sector currently consumes about 38 percent of its total annual billed sales. BC Hydro states that industrial electricity consumption is tied closely with the level of economic activity in the province, market conditions and prices, and world and domestic events that impact sales. Future economic trends, measured by provincial GDP are good indicators of future electricity consumption by the sector since industrial sales are closely correlated with economic growth.

BC Hydro states that its Load Forecast is sensitive to a number of factors, including economic conditions, weather, DSM, electricity rate structures, electricity rates and elasticities. A composite sensitivity analysis using a Monte Carlo model is included in this forecast, the results of which are represented as the High, Medium and Low Load Forecasts (Exhibit B-1-1, Appendix D, pp. 10-12 of 103).

6.3.3 Material Changes to the BC Economy

A number of Intervenors question BC Hydro's cut-off point of October 2008 and observe that the BC economy was still in decline at that time.

BC Hydro notes that the major exception to the October 2008 cut-off date was the customer-by-customer information included in the transmission (industrial) customer forecast, which was current to December 2008.

BC Hydro submits that "There is always a need for an evidentiary cut-off date. Preparing forecasts and updating analysis based on new forecasts is a series of complex processes that take time" (BC Hydro Argument, p. 86). BC Hydro also notes that the actions identified in the 2008 LTAP are focused on BC Hydro's long-term requirements rather than its short-term requirements and that its expectation was that "the mid- to long-term economic expectations remained substantially the same as those presented in the Evidentiary Update" (BC Hydro Argument, p. 87).

The CEC recommends that "the Commission reject the Load Forecast of BC Hydro as being inadequate for the purpose of justifying material and costly supply side options…and...BC Hydro should be directed to provide an updated Load Forecast to the Commission as soon as possible to reflect the material changes in the British Columbia economy, which have not been reflected in the BC Hydro forecast" (CEC Argument, p. 4).

In Reply, BC Hydro takes exception to CEC's introduction of a "significant amount of new evidence," and in particular its assertions with respect to economic and market conditions after the close of the 2008 LTAP evidentiary record.

BC Hydro submits that the economic forecasts it used to prepare its load forecasts must necessarily consider a long-term perspective and they consistently indicate a recovery in the 2010 timeframe, which, when considered over the medium-to long-term, will raise ultimate economic activity levels to be in line with the projections that were used in the Evidentiary Update (BC Hydro Reply, p. 41).

6.3.4 Intervenors' Criticisms of BC Hydro's Methodology

CEC identifies seven perceived deficiencies in BC Hydro's load forecasting methodology:

- it systemically produces "over and under load forecasts in synchrony with the ups and downs of the prior economic cycles… this is a logical outcome or function of the curve fitting techniques used in generating the forecast projections";
- it does not anticipate economic cycles in the future, but adopts "relatively straight line forward projections of past experience";
- during economic downturns it "consistently has to re-establish the anchor point to existing load by dropping estimates from its previous over-forecasts";
- it uses third party forecasters who "have consistently underestimated the current economic recession";
- the residential load forecast uses optimistic future projection variables for account growth and average use per account that cannot be justified;
- the commercial load forecast uses optimistic future projection variables for account growth and average use per account that cannot be justified; and
- the industrial load forecast does not recognize the consequences of the full extent of the collapse of the US housing market and its evolving impacts on the forest sector businesses, it anticipates significant new mine loads, and it does not recognize the extent of the commodity price uncertainty and financial crisis.

(CEC Argument, pp. 46-47)

Citing BC Hydro's testimony at T7:1115, CEC contends that BC Hydro has utilized regression model techniques that fit past data to a straight line. It also states that BC Hydro's use of five years of history is not sufficient for line fitting to account for economic cycling of the economy (CEC Argument, pp. 53-56). CEC further contends that BC Hydro has a track record of over-forecasting that arises from its forecasting methodology (CEC Argument, pp. 50-53).

BC Hydro characterizes CEC's comments as "sweeping and inaccurate allegations" and responds that it has significantly improved its forecasting methodology since 2005 and that CEC's Argument related to past forecasts is of little relevance to the 2008 Load Forecast Update (BC Hydro Reply, pp. 36-37).

BC Hydro further replies that its forecast is not generated simply based on curve-fitting techniques; it employs more sophisticated approaches including bottom up approaches for residential customers, detailed end-use information for commercial customers, and expected activities for individual industrial (transmission) customers (BC Hydro Reply, pp. 37-41).

IPPBC submits that there may be certain deficiencies in BC Hydro's load forecasting methodology because some of the "historical data already contains imbedded impacts of the historical DSM programs that were underway before and during the period of analysis" (IPPBC Argument, p. 4). BC Hydro concurs with this observation and allows that this issue is currently a key research issue related to integrated resource plans in the utility industry. This is one item "that BC Hydro considers necessary to be addressed more fully before its next LTAP" (BC Hydro Reply, pp. 42-43).

Pursuant to item 2 of the Commission Panel's agenda for the Oral Phase of Argument, the Commission Panel invited submissions on the position taken by certain parties that BC Hydro's long-term forecast methodology was flawed or otherwise deficient and requested further submissions (a) with particular respect to the statistical basis underlying the basic trend line, i.e., the number of years of prior data considered and, (b) given the 20-year term of the forecast, whether it was reasonable to not include or otherwise illustrate the effect of economic cycles (Exhibit A-20).

BC Hydro submitted that the starting point of the forecast was appropriately adjusted using current information such that the issue of changing the number of years of prior data considered was "largely irrelevant" (T16:2868).

On the matter of economic cycles BC Hydro submitted that "at least in the near-term" its forecast did consider the effects of current and reasonably foreseeable economic conditions, but that "beyond approximately three years out neither BC Hydro nor…any credible forecaster, would admit the ability to predict the timing or even the existence of future economic cycles" (T16:2868).

JIESC, IPPBC and BCSEA essentially supported BC Hydro's approach. CEC submitted that what concerned it was the impact an overstated load forecast would have on BC Hydro's revenue requirements at this time and pointed out BC Hydro's failure to meet the test of being over half the time and being under the other half. It reiterated the relief it sought which was that the Commission reject the 2008 Load Forecast Update (and thus the 2008 LTAP by inference) and direct BC Hydro to re-file an LTAP in June 2010 (T16:2879-84).

BCOAPO supported CEC in its concern regarding the impact of over-forecasting demand on BC Hydro's revenue requirements, and that it saw "significant ratepayer benefit in including a maximum number of years of prior data possible, or practicable on a statistical basis, used to generate the basic trend line," while agreeing with BC Hydro that accurate prediction of future trends was "impossible." BCOAPO further noted that use of an expanded number of years in BC Hydro's trend line could provide a better basis on which to predict better probabilities of events such as downturns and recessions (T16:2884-86).

BC Hydro made no further submissions.

6.3.5 Potential Future Load Growth

BC Hydro notes that "potential loads such as electric plug-in vehicles ("EPVs") have not specifically been factored into the Load Forecast" (Exhibit B-1, p. 2-2). BC Hydro states that it has analyzed potential electrification load (such as EPVs and fuel choice in residential electric space and water heating applications) and submits that it is still too uncertain include in the load forecast, and that including these two scenarios in the 2008 Load Forecast Update would be inappropriate, because, among other things, it would lead to BC Hydro acquiring more resources than it requires at this time, thus exposing customers unnecessarily to additional costs (BC Hydro Argument, p. 60).

BC Hydro submitted that it will have several years warning with respect to growth in the EPV load, that it is monitoring EPV production targets of major manufacturers and that it is participating in EPV research through the Electric Power Research Institute (BC Hydro Argument, p. 60).

IPPBC submitted that BC Hydro's "base load forecast does not include 1 kWh for the potential load from these electric vehicles." IPPBC contrasts the testimony given by BC Hydro on February 20, 2009, that "we cannot build things into our load forecasts based on anecdotal evidence" with the press release issued on March 9, 2009 by BC Hydro which stated "Major auto manufacturers have announced plans to introduce electric models in the coming year, and early forecasts suggest anywhere from 10 to 60 percent of new vehicles purchased by 2025 will be electric vehicles" and to announce that after a competitive call for proposals, BC Hydro had contracted for a study to detail the necessary actions for deploying electric vehicle charging infrastructure. (IPPBC Argument, p. 13)

Following the close of the evidentiary phase of the proceedings and in advance of the parties filing written argument, the Commission Panel provided the parties with a list of issues that it asked parties to comment upon (Exhibit A-21). Issue number 5 invited submissions on whether the evidentiary record should be re-opened to admit evidence of BC Hydro's participation in a BC Government led program relating to electric vehicles and BC Hydro's engagement of consultants, pursuant to a call for proposals, to detail the necessary actions for deploying EV charging infrastructure, with a report to be filed by the end of April, 2009. Additionally, Issue Number 5 asked that, if the evidentiary record was to be reopened, should parties be given the opportunity to examine the new evidence and make submissions as appropriate, and if so, by what process.

BC Hydro opposes the re-opening the evidentiary record on the basis of the pilot program described above, which consists of testing one EPV to be added to the BC Hydro fleet – the first production ready, highway capable EPV. BC Hydro would not modify the 2008 Load Forecast Update on the basis of this pilot program (BC Hydro Argument, p. 61). This view was shared by CEC, JIESC, BCOAPO and BCSEA, while COPE took no position.

IPPBC submits that the evidentiary record should be re-opened and BC Hydro's witnesses who provided responses to the IPPBC's questions about why the demand for electric vehicles is not included in the load forecast be asked to explain the apparent differences in their evidence and BC Hydro's subsequent actions (IPPBC Argument, p. 51).

Commission Determination

The Commission Panel does not agree with CEC that BC Hydro should be directed to provide an updated load forecast to the Commission as soon as possible to reflect the material changes in the British Columbia economy. In the Commission Panel's view, BC Hydro has prepared a long-term forecast for planning purposes that reasonably recognizes the province's economic condition.

The Commission Panel has considered CEC's request that the Commission Panel find that BC Hydro's 2008 Load Forecast Update overstates load by 1,000 GWh/year by 2016. **While the Commission Panel recognizes the potential for both over-statements and under-statements in the 2008 Load Forecast Update, it rejects CEC's request to provide the Commission as soon as possible with an updated load forecast.**

Accordingly the Commission Panel accepts BC Hydro's 2008 Load Forecast Update for the purposes of its review of the 2008 LTAP. The Commission Panel also notes that BC Hydro agrees with IPPBC that there is some potential for double counting of DSM in the forecasting coefficients and requires BC Hydro to address this in its next LTAP.

The Commission Panel shares CEC's and BCOAPO's concerns that five years of past history is inadequate to assess the economic cycling in the economy should such methodology be in place, and notes that BC Hydro did not specifically address the five-year issue in its Reply.

In the Oral Phase of Argument, BC Hydro contended that "[T]he starting point of the forecast is appropriately adjusted using current information, and therefore in BC Hydro's respectful submission, the issue of changing the number of years of prior data considered is largely irrelevant." The Commission Panel notes the apparent inconsistency of that submission with BC Hydro's testimony at T7:1115 that it uses statistically adjusted end-use regression models to support the residential and commercial sector load forecast to project forward from five years of historical data.

To address Intervenors' concerns and to enable the Commission to review BC Hydro's projections of load on an informed basis, the Commission Panel believes it would be helpful in understanding the assumptions underpinning the load forecast to have before it that baseline projection. Therefore the Commission Panel requires BC Hydro in its next LTAP to provide in tabular and graphical form at least ten years of past actual consumption by four classes of customer – Residential, Small Commercial, Large Commercial, and Industrial - and the resultant total demand thereof. It also requires the provision of the 20-year projection of the statistical best fit extension of that data based on a simple linear regression of loads and a time trend. This should be separate from its own projections of demand for those classes and the total thereof for the same forward 20-year period. BC Hydro is required to explain the factors used as inputs to its forecast that may cause any differences between its forecasts, and the statistically derived "base line forecasts" for several snapshots in time during the 20-year forecast for each of its customer classes.

The Commission Panel denies IPPBC's request to re-open the record to hear more evidence on EPVs as it considers that the issue was adequately canvassed during the proceeding.

The Commission Panel considers that potential new loads such as EPVs were envisaged in Policy Action 10 of the 2007 Energy Plan which addressed the "challenges of forecasting future needs" as being one reason for BC Hydro to ensure self-sufficiency to meet and exceed its electricity supply obligation and has addressed self-sufficiency earlier in Section 6.2 of this Decision.

6.4 Demand-Side Measures

This Section addresses BC Hydro's DSM proposals in the 2008 LTAP in the context of the regulatory framework as summarized at Section 1.2 of this Decision. It describes how BC Hydro developed its DSM savings (both energy and capacity) and the expenditures necessary to achieve them. It next addresses the definition of "cost-effective" DSM and considers whether BC Hydro looked at adequate cost-effective DSM. The relief sought by BC Hydro and by other Intervenors, including BC Hydro's expenditure requests related to DSM, amortization of DSM expenditures, measurement and reporting of DSM along with other DSM matters are dealt with in Section 7 of this Decision.

6.4.1 Regulatory and Legislative Requirements

Section 1 of the *Act* defines "demand-side measure" as:

> "a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand."

While subsection 44.1 (2) requires BC Hydro to include in its long term resource plan:

> "(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan; (b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures; and (f) an explanation of why the demand for energy to be served by…are not planned to be replaced by demand-side measures."

Subsection 44.1 (8) (c) requires the Commission to consider, when determining to accept the plan: "whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures."

Subsection 4 (1) of the M271 states that in determining for the purposes of section 44.1(8)(c) or 44.2(5)(d) the cost-effectiveness of a proposed demand-side measure proposed in an expenditure portfolio or a plan portfolio, the Commission *may*:

> "compare the costs and benefits of (a) the demand-side measure individually, (b) the demand-side measure and other demand-side measures in the portfolio, or (c) the portfolio as a whole,"

while subsection 4(6) of M271 states that the Commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure ("RIM") test to assess the demand-side measure.

Section 3 of SD 10 defines, in part, electricity supply obligation as being …"determined by using the authority's mid-level forecasts of its energy requirements and peak load, taking into account demand-side management initiatives…"

6.4.2 BC Hydro's DSM Approach

6.4.2.1 Introduction

This Section reviews the development of BC Hydro's proposed energy and capacity savings from DSM. Section 6.4.2.2 describes the 2007 CPR. Section 6.4.2.3 describes how BC Hydro identified the components of its DSM initiatives and developed two separate options of DSM initiatives (Options A and B). The section describes the various components, and the two options and how they differ. Section 6.4.2.3 describes the probability analysis BC Hydro performed on the two options to develop risk-adjusted energy and capacity savings, which it then updated and refined for inclusion in the Application. Section 6.4.2.4 describes the methodology BC Hydro used to make its final adjustments to Option A for inclusion in its Evidentiary Update.

The table below sets out the four sets of DSM savings figures for Option A for F2020 in the 2008 LTAP. The first column, entitled Point Estimate, represents BC Hydro's initial estimate of savings, which were inputs to the probability assessment which took line losses into account and produced a second set of figures, comprising high, mid, and low DSM outcomes with associated probabilities.

The mid-outcome is set out in the second column entitled "Probability Analysis." The third column is the result of updates and refinements that were carried out after it was submitted for the portfolio analysis so that the DSM expenditure request in the Application would be based on the most recent available information. BC Hydro states that the differences between the first three columns are small and not material (Exhibit B-1, p. 6-2). The fourth column is found in the Evidentiary Update and reflects adjustments made by BC Hydro in recognition of the updated Load Forecast (Exhibit B-10, p. 21).

DSM Savings – F2020 Option A

	Point Estimate	Probability Analysis	Original Application	Evidentiary Update
GWh	10,820	10,605	10,900	9,600
MW	1,730	1,756	1,850	1,679

(Source: Exhibit B-1, p.3-7, Exhibit B-1-1, Appendix K, p.101 of 213, Exhibit B-1, p.5-46, and Exhibit B-10, p. 21)

6.4.2.2 2007 Conservation Potential Review

BC Hydro discusses its DSM strategy in Section 2 of Appendix K to the 2008 LTAP. BC Hydro states that the starting point for its DSM strategy is an estimate of the electricity conservation and efficiency "resource", being the potential to save electricity through DSM measures. A CPR and specific research on Codes and Standards and Rate Structures contributed to its estimate of the resource.

BC Hydro states that its fourth CPR was undertaken in 2006 and 2007, and that its purpose was to estimate the potential energy and capacity savings that could be achieved among BC Hydro's customers over the twenty-year period 2006 to 2026 through electricity conservation and efficiency, fuel-switching and customer-supplied renewable energy. The CPR was a consultative effort involving BC Hydro's staff, a consulting team, an external review panel and industry experts, as described at section 4.0 of this Decision.

BC Hydro further states that the range of achievable potential depends on market conditions, government policy, and DSM measures. It provided Table 1 which presents the CPR estimates of achievable and economic conservation potential.

Table 1. Combined Achievable and Economic Conservation Potential in F2021 (GWh/yr[1])

	Lower Achievable	Upper Achievable	Economic
Residential	1,978	2,994	5,784
Commercial	2,052	2,926	5,170
Industrial	2,137	4,849	8,063
Total	**6,167**	**10,769**	**19,017**

BC Hydro explains that the lower achievable potential assumes that market conditions, program efforts, and incentive levels remain at current levels, while the upper achievable assumes that market conditions and government policy are supportive and that energy savings are aggressively pursued. The upper achievable potential does not represent the maximum achievable energy conservation potential in the province but rather an estimate of this potential based on the CPR's scope and assumptions, including the assumed rate of adoption of efficiency measures. Additional savings are possible through changes that are not reflected in the above estimates, such as lifestyle changes, emerging technologies beyond 2011 and step-changes in energy efficient technologies (Exhibit B-1-1, Appendix K, p. 6).

<u>6.4.2.3 DSM Option A and Option B Initiatives</u>

BC Hydro states that it identified three principal components of its DSM initiatives: Codes and Standards, Rate Structures, and specific programs targeted at different classes of customers, and that these three components are supported by a fourth component, comprising initiatives such as public awareness and education, community engagement, and technology innovation.

BC Hydro states that Codes and Standards refer to a range of government policy instruments that can influence energy efficiency, including regulations on equipment, buildings or labour, tax measures, and municipal zoning and building permitting processes. Such measures can mandate a minimum level of energy efficiency for buildings or a product, thereby eliminating the worst performing building design practices and products from the market. BC Hydro states that subsection 44.1 (4) (c) of the *Act* anticipates the inclusion of Codes and Standards in BC Hydro's long-term resource plans.

BC Hydro states that Rate Structures can deliver a conservation price signal to consumers while continuing to recover the appropriate amount of revenue in a cost-based regulatory environment.

BC Hydro states that DSM programs deliver information, technical assistance, financial incentives and quality assurance to consumers to address the specific barriers that affect a given energy savings opportunity and market segment. DSM programs typically operate in the individual context, but can also operate in the market context by influencing suppliers of energy efficiency goods and services and by setting the stage for the introduction and enhancement of energy efficiency codes and standards (Exhibit B-1-1, Appendix K, pp. 10-11).

For planning purposes BC Hydro states that it considered two separate options of DSM initiatives, Option A and Option B. While Option A and Option B utilize the same DSM tools, Option B utilizes different actions and tactics to achieve greater savings.

Table 3-4 DSM Electricity Savings and Costs[34]

Option	Planned Energy Savings in F2020 (GWh/year)	Planned Capacity Savings in F2020 (MW)	All Ratepayers (Total Resource) Levelized Cost ($/MWh)[35]
A	10,820	1,730	41
B	13,030	2,100	42

(Exhibit B-1, p. 3-7)

BC Hydro focuses on the cumulative DSM savings in F2020 because of Policy Action 1 of the 2007 Energy Plan which sets a target of 10,000 GWh by 2020.

BC Hydro states that Options A and B achieve 57 percent and 69 percent respectively of the economic potential identified in the 2007 CPR, but that it views as "highly uncertain" the possibility that 100 percent of the economic potential identified in the 2007 CPR could be achieved, as to do so would require it to overcome all barriers to cost-effective energy efficiency and conservation opportunities (Exhibit B-3, CEC 1.5.5).

BC Hydro states that the development of Option A involved independent decisions on the components within each of Codes and Standards, Rate Structures and programs which, when integrated into a combined option, resulted in the cumulative planned energy savings in F2020 of 10,820 GWh per year. Since this exceeded the "ambitious conservation target" of 10,000 GWh by 2020 figure set out in Policy Action No 1 of the 2007 Energy Plan, BC Hydro left it unchanged for the purpose of portfolio analysis. BC Hydro states that its Option B comprises additional or different actions and tactics to achieve incremental electricity savings.

BC Hydro acknowledges that additional savings beyond Option B may be feasible, but states that it did not include them because they are too uncertain for the purpose of resource planning at this time. It also did not analyze an option smaller than Option A because of the target established in Policy Action No. 1 of the 2007 Energy Plan, which BC Hydro interpreted as a call for DSM savings of at least that amount, and 2007 Energy Plan Policy Action No. 3, which called on utilities "to pursue all cost-effective investments in demand-side management." BC Hydro notes that Policy Action No. 3 has now been given the force of law pursuant to subsection 44.1(2)(b), which provides that public utilities must file a long-term plan that shows how the public utility intends to reduce demand by taking cost-effective demand-side measures. As such, BC Hydro used Options A and B in its 2008 LTAP portfolio analysis (Exhibit B-1, p.3-7).

6.4.2.4 Probability Analysis

BC Hydro notes that estimates of DSM savings are subject to considerable uncertainty, and in order not to have to rely on point estimates it developed a range of possible outcomes. Each of Codes and Standards, Rate Structures and programs were analyzed to elicit ranges and probabilities around the energy savings estimates, following which a number of Monte Carlo analyses were run to estimate the expected levels of energy savings and the spread of outcomes around the means (Exhibit B-1-1, Appendix F14, p. 15 of 29).

BC Hydro summarizes the results of its mid-point probability analysis forecast DSM for F2020 as follows:

Mid-point Probability Analysis Forecast DSM for Option A for F2020

GWh/year	Residential	Commercial	Industrial	Total
Codes and Standards	2,763	500	106	3,369
Rate Structures	978	387	727	2,092
Programs	1,070	1,472	2,592	5,015
Total	4,811	2,369	3,425	10,605

(Source: Exhibit B-1-1, Appendix K, p. 101 of 213)

6.4.2.4.1 Codes and Standards

BC Hydro summarizes its planned savings from Codes and Standards from Option A in F2020 in the following table:

Table 1. Energy Savings from Codes and Standards

Category	Components	Energy Savings in F2020 (GWh/year)
Electronic equipment	Standby power, set-top boxes, external power supplies, battery chargers	1,311
Incandescent lighting		845
Other residential equipment	Windows, ceiling fans, furnace blower motors, torchieres, hot tubs, small motors, room air-conditioners	537
Building code		353
Appliances	Clothes washers, refrigerators, freezers, dishwashers	158
Large motors		125
Commercial equipment	High intensity discharge lamps and ballasts, packaged terminal air-conditioners, ice-cube makers, large air-conditioners, commercial clothes washers	38
Total		**3,367**[23]

(Exhibit B-1-1, Appendix K, pp. 10 & 120)

BC Hydro lists 22 federal or provincial regulations it expects to be introduced in the years 2008-2012 and one major federal government initiative announced for 2016, a "ban on inefficient incandescent lights" which it forecasts will save 845 GWh/year in F2020. Other major sources of savings relate to harmonization of Canadian regulations with those of California on standby power and set-top boxes, which BC Hydro estimates will save a combined 995 GWh/year in F2020. The split of savings is as follows: from enacted regulations 5 percent, from announced regulations 41 percent, and from planned regulations 54 percent. (Exhibit B-1-1, Appendix K, p. 129)

BC Hydro states that Option B assumes 6 more regulations none of which are being planned by either government and which it estimates could garner additional savings of 212 GWh in F2020 (Exhibit B-1-1, Appendix F 17, p. 4).

6.4.2.4.2 Rate Structures

BC Hydro sets out its forecast savings from Rate Structures from Option A in F2020 in the following table:

Table 5. Planned Energy Savings from Rate Structures

Sector	Rate Class	Estimated Energy Savings in F2020 (GWh/yr)
Residential	Residential	980
Commercial	Small general service	140
Commercial	Large general service	250
Industrial	Large general service	270
Industrial	Transmission	460
Total[26]		**2,090**

(Exhibit B-1-1, Appendix K, p. 135)

BC Hydro states that its residential and transmission customers are already seeing inclining block rate structures and it has assumed that its small and large general service customers will see them in F2010. The parameters it has assumed in its estimate for its small and large general service customers are a two step inclining block rate with Step 1 being held constant in real terms and the residual increases in revenue requirements being reflected in Step 2. BC Hydro states that Option B assumes the same parameters with the exception of the threshold between Tier 1 and Tier 2 (Exhibit B-1-1, Appendix K, pp.131-24 of 213 and Exhibit B-1-1, Appendix F 17, p. 6 of 9).

6.4.2.4.3 Programs

BC Hydro states that the DSM programs in Option A were designed to increase electricity savings from programs in the F2008-F2020 period over historical levels, while programs in Option B were designed to further increase participation levels using higher incentive levels and marketing efforts (Exhibit B-1. p.3-5).

BC Hydro identifies the 21 programs in Options A and B as follows:

Table 3-3 DSM Programs in Option A and B

Residential	Commercial	Industrial
Behaviour	Power Smart Partner	Mechanical Pulping
Voltage Optimization	Product Incentive	Power Smart Partner - Transmission
Lighting	High Performance Building	Power Smart Partner - Distribution
Sustainable Community	Voltage Optimization	New Plant Design
Refrigerator Buy-Back	Sustainable Community	Load Displacement
Renovation Rebate	Load Displacement	
New Home		
Low Income		
Appliances and Electronics		
Load Displacement		

(Exhibit B-1, pp. 3-5)

6.4.2.4.4 Capacity Savings

BC Hydro identified three key drivers of uncertainty when estimating capacity factors:

- measurements of peak load;
- the shape of energy savings applied to load; and
- extrapolating results into the future (forecasting).

BC Hydro derived a range of capacity factors and a best estimate for each customer class that took into account these factors. Using a Monte Carlo simulation BC Hydro developed the following estimate of capacity reduction resulting from Option A in F2020:

Mid-Point Probability Analysis Forecast of Capacity Reduction from Option A in F2020

MW	Residential	Commercial	Industrial	Total
Codes and Standards	584	65	14	662
Rate Structures	217	63	95	375
Programs	202	194	332	719
Total	1,003	322	430	1,756

(Source: Exhibit B-1-1, Appendix K, p. 22)

6.4.2.5 Evidentiary Update

BC Hydro states that the reduction in load between the 2006 Load Forecast and 2008 Load Forecast Update has an effect on the amount of economic conservation potential in its service territory. Pointing to F2021, BC Hydro notes that the 2008 Load Forecast Update is 2,600 GWh lower than the 2007 Load Forecast, but 5,500 GWh lower than the 2006 Load Forecast, which was the forecast upon which the 2007 CPR determined its reference case forecast of electricity use. BC Hydro estimates that of this 5,500 GWh decrease, 1,470 GWh was the result of the customer response to higher rate levels between the 2006 and 2008 Load Forecasts, with the balance of some 4,000 GWh being attributable to changes in the economic drivers and production forecasts underlying electricity load.

To adjust Option A savings BC Hydro assumed that all 1,470 GWh of the rate level savings overlapped with the economic conservation potential estimated in the 2007 CPR, because BC Hydro expects higher rate levels to spur customers to undertake lower cost electricity saving actions that would have been included within the economic conservation potential. BC Hydro further assumes that 30 percent of the reduction of 4,000 GWh in load due to changes in economic drivers and production forecasts overlaps with the economic conservation potential, on the grounds that only a portion of load represents “uneconomic” consumption that could be avoided through economic conservation. The 30 percent assumption used in BC Hydro’s analysis is derived from the approximate ratio of economic conservation potential in the 2007 CPR to the forecast load before DSM. As a result, BC Hydro estimates that the economic conservation potential is 2,400 GWh lower in F2021 relative to that estimated in the 2007 CPR (16,600 GWh as compared to 19,000 GWh).

BC Hydro states that the above changes are sufficient in BC Hydro's view to warrant changes to the level of expected DSM savings for resource planning purposes in the 2008 LTAP from 10,900 to 9,600 GWh by F2020. BC Hydro states that the degree of analysis required did not justify the generation of a new CPR or analysis of the impacts of the above changes on an initiative-by-initiative basis. BC Hydro has commissioned CPRs only every five years or more due to their considerable cost and effort.

BC Hydro states that it considered the impacts of the load forecast changes on DSM deliverability risk, undertook a high level analysis, and reviewed its level of reliance on DSM. It concluded that sufficient economic conservation potential remains to support the original DSM target of 10,900 GWh in F2020, but that the level of risk associated with achieving this amount of DSM savings has increased due to the reduction in economic conservation potential. To adjust for this increased risk, BC Hydro will continue to implement the same DSM initiatives,but will reduce its expectation of the savings that will result. Even with the same level of expenditures and a reduced level of expected savings, BC Hydro claims that DSM remains cost-effective relative to new supply-side resources.

To adjust the level of expected savings it would rely upon, BC Hydro used the previous share of the economic conservation potential that was represented by the DSM Plan and reduced the expected level of savings from the DSM Plan to restore that same share given the reduction in the economic conservation potential. DSM Option A would have captured 54 percent of the old economic conservation potential and, all else equal, would now capture 61 percent of the new economic conservation potential. BC Hydro adjusted the level of expected DSM savings by 11 percent such that the expected DSM savings continue to be 54 percent of the new economic conservation potential.

BC Hydro also examined the degree of reliance on DSM in the period up to 2020. DSM represented 78 percent of the F2020 14,000 GWh load/resource gap it set out in Chapter 6 of its 2008 LTAP. Reducing expected DSM savings by 11 percent from 10,900 GWh to 9,600 GWh would mean DSM represents approximately three quarters of the F2020 13,400 GWh load/resource gap, which represents a similar level of reliance on DSM as presented in the 2008 LTAP. BC Hydro also examined the proportion of incremental load that would be met by DSM. DSM would have met 90 percent of BC Hydro's incremental energy load between F2008 and F2021 in the 2007 Load Forecast. DSM Option A would now meet 109 percent of incremental energy load in the 2008 Load Forecast Update. Reducing expected DSM savings by 11 percent would mean DSM meets 94 percent of incremental energy load between F2008 and F2021 in the 2008 Load Forecast Update (Exhibit B-10, pp.20-23).

On a similar basis, BC Hydro reduced the forecast of capacity savings by approximately 10 percent from 1,850 MW to 1,679 MW (Exhibit B-10, p.16).

6.4.3 Cost-effective DSM

6.4.3.1 Criteria for cost-effective DSM

For the purposes of this and other 2008 LTAP-related matters, BC Hydro references and relies upon a definition of cost-effectiveness employed by the Commission in its Decision *In the Matter of British Columbia Transmission Corporation: an Application for a Certificate of Public Convenience and Necessity* ["CPCN"] *for the Vancouver Island Transmission Reinforcement Project,* Decision dated July 7, 2006 ("VITR Decision").

At page 15 of the VITR Decision, the Commission stated that:

> "The task before the Commission Panel is to select amongst competing project alternatives and amongst route options and designs for VITR. As stated in the previous paragraph, private interests are to be considered in this Decision. The description of "cost-effective" as described in the VIGP Decision [*In the Matter of Vancouver Island Energy Corporation*

> ("VIEC") *(a wholly-owned subsidiary of BC Hydro) Vancouver Island Generation Project: an Application for a Certificate of Public Convenience and Necessity,* Decision dated September 8, 2003] provides further clarification of the appropriate considerations. The task is not to select the least cost project, but to select the most cost-effective project. Therefore as suggested by BC Hydro, reliability, safety, schedule, financing arrangements and other factors itemized in the VIGP Decision and revised by BC Hydro are also relevant to the task before the Commission Panel. In this regard, the Commission Panel accepts BC Hydro's view of the considerations that can be included in the definition of cost-effective."

At page 77 of the VIGP Decision the Commission stated VIEC's position as:

> "'The touchstone is to issue a CPCN, the Commission must be satisfied that this is the most cost effective way to reliably meet the needs.'
>
> The principal distinction between most cost-effective and least-cost is the scope of considerations that are relevant. In the context of this Decision, most cost-effective includes consideration of project characteristics such as reliability, dispatchability, timing and location as well as the cost or price, in the case of an [Energy Purchase Agreement]. Least-cost is taken to include only cost or price considerations."

BC Hydro submits that it has used the VITR definition of cost-effectiveness "which in addition to low cost includes schedule/deliverability risk, reliability, timing, location and environmental impacts" (BC Hydro Argument, p. 16). BC Hydro defines deliverability risk as "the risk that the DSM options do not deliver the projected electricity savings within the specified time frame" (Exhibit B-1, pp. 5-54).

In its opening statement JIESC submitted that cost-effectiveness for the purposes of this review was "the lowest long term cost consistent with government policy as set out in the Energy Plan, the *Act* and the Regulations," and further, in its Argument submits that "the Commission['s] discretion as to the cost-effectiveness of DSM remains unfettered in the case of a large majority of DSM Programs" (JIESC Argument, p. 19). ESVI submits that "the use of the extra factors of *"deliverability risk"* are not substantiated for the definition of cost-effectiveness, are not supported by evidence in this proceeding" (ESVI Argument, p. 16). CEC submits that the appropriate test of cost-effectiveness is "can the DSM initiatives be planned, undertaken and savings delivered at less than the avoided cost of supply with a reasonable degree of certainty?" (CEC Argument, p. 85).

BC Hydro submits that ESVI was the only Intervenor to contradict the view that cost-effectiveness should take deliverability risk into account and points to the Commission's use of the term "includes" in the VITR Decision as demonstrating that cost-effectiveness must consider a number of externalities. BC Hydro submits that ESVI's submission in this regard is not substantiated and "ought to be ignored" (BC Hydro Reply, p. 51).

Commission Determination

The Commission Panel notes firstly that the particulars in the VITR and VIGP Decisions have little in common with those in this proceeding. The VITR proceeding involved selection amongst project execution alternatives which impacted private, as well as ratepayer, interests. The VIGP proceeding involved the public interest tests pursuant to its review of a capital project for which a CPCN was required. In both of the proceedings the tension was between the lowest or least-cost execution of the project and the impacts on those affected by the project.

In the context of this LTAP, the framework is that of a "zero-sum game" as a result of the combined requirements of SD 10 in respect of self-sufficiency criteria and section 44.1 in respect of the priority of DSM over new electricity supply. In other words, the tension is between the risk and non-economic consequences of a shortfall (or excess) in the results delivered by a DSM program and the economic consequences to ratepayers of the acquisition of new electricity supply by BC Hydro, which supply might otherwise not be required.

There is no conflict between "least-cost" and "cost-effective" as existed in the proceedings referenced by BC Hydro. In this LTAP, for both aspects – DSM driven reduction in the need for supply, and new supply itself, there are different levels of cost at different levels of achievement. As well, there are risks involved in both. These matters are explored and considered in greater detail later in this Section.

Accordingly, the Commission Panel finds that acceptance of, and/or undue weighting of, any particular prescriptive criteria for cost-effectiveness advanced by BC Hydro or any Intervenor would unduly fetter its discretion to make such determinations within the context of this proceeding. The Commission Panel will make its determinations based on the evidence before it.

6.4.3.2 Quantifiable aspects of cost-effectiveness

BC Hydro calculates the unit energy cost ("UEC") of a DSM program by calculating the net present value of the sum of (1) program costs, (2) participant costs, (3) BC Hydro portfolio costs, and (4) partner costs, and dividing this total by the net present value of energy savings. BC Hydro states that it is valid to compare the UEC thus calculated with the UEC of a supply-side project.

IPPBC submits that comparing TRCs to IPP prices is "like comparing apples to oranges" noting that the supply–side prices from IPPs are really more like RIM costs than TRCs (IPPBC Argument, p. 26).

BC Hydro submits that IPPBC appears to be confused about the nature and purpose of the DSM cost tests and that only the TRC cost test captures the full cost of DSM and, for that reason, BC Hydro submits that IPP prices are more like TRC costs than RIM costs (BC Hydro Reply, p. 54).

JIESC submits that with the exception of those limited areas where portfolio level scrutiny is mandated the Commission should determine the cost-effectiveness of Demand Side Measures or programs individually and determine their cost effectiveness in comparison to supply side or Resource Smart alternatives (JIESC Argument, p. 7).

BC Hydro responds that "while the TRC cost test is the appropriate benefit/cost test for comparing DSM to other resources, the levelized TRC tends to underestimate the cost-effectiveness of DSM programs because, unlike the TRC benefit/cost ratio, the levelized TRC does not represent the full benefits of DSM programs. For example, the levelized TRC does not include the value of avoided regional transmission or distribution capacity costs" (BC Hydro Reply, p. 64).

Commission Determination

The Commission Panel agrees with BC Hydro and finds that when comparing the UEC of a DSM program with the UEC of a supply-side option, the appropriate metric upon which to compare levelized $/MWh is the TRC.

That notwithstanding, there is considerable uncertainty implicit in the comparison between the UEC of a DSM program and that of a supply-side resource, including, without limitation, the location of that resource, whether to factor into the UEC a value for capacity including the use of energy weighting factors, and the value of avoided regional transmission or distribution capacity costs, if any. In addition, there is the matter of the appropriate allocation of savings between DSM programs and savings from response to rate increases that are driven by price-elasticity. In the view of the Commission Panel these issues need to be studied further to ensure that the UECs of DSM programs are correctly calculated.

Accordingly the Commission Panel requires BC Hydro to address in its next LTAP a methodology for comparing risk-weighted UECs of demand side measures and of physical supply-side resources.

6.4.4 Adequacy of BC Hydro's DSM Portfolio

BC Hydro submits that it selected Original Option A because:

- it is considerably lower cost than new supply;
- it avoids a number of supply-side risks;
- the majority of its risks can be managed or mitigated; and
- it is consistent with the requirements of the *2008 UCA Amendments* to pursue all cost-effective DSM.

(BC Hydro Argument, p. 122)

BC Hydro's analysis of the cost-effectiveness of DSM was by way of portfolio analyses which compared three scenarios: no DSM, Option A and Option B, with Option B proving more cost-effective than Option A under all but the "low gap, low gas, low GHG" scenario, and both Options A and B proving more cost-effective than the No DSM scenario (Exhibit B-1, pp. 5-49 to 5-54).

The supply-side risks avoided by DSM include First Nations, siting, GHG and commodity costs, and transmission issues (Exhibit B-1, p. 5-49).

BC Hydro defines deliverability risk as the risk that the DSM Options do not deliver the projected electricity savings within the specified time frame. Its assessment of deliverability risk focused on the ability to achieve the forecast DSM savings and the implications of not achieving those savings, and included consideration of:

- the expected variability of the resource;
- the degree of reliance on the resource (e.g., how much of the gap is met by the resource); and
- the proven success of similar programs in either BC or in other jurisdictions.

(Exhibit B-1, pp. 5-54,55).

BC Hydro asserts that a subjective assessment of this risk is appropriate because "the application of the Risk Framework to DSM was a first-time effort that involved eliciting probability assessments regarding DSM tools that were new to BC Hydro DSM planning, such as codes and standards and conservation rate structures, and programs that involved higher levels of effort that previous years" (Exhibit B-1, pp. 5-55).

BC Hydro submits that it did not select a lesser amount of DSM savings because that would have foregone substantial cost savings and exposed BC Hydro and its ratepayers to more supply-side risks, and that it did not select Option B because, even though the additional savings would come at a considerably lower unit cost (if the savings were realized) than new supply, it would not be cost-effective because it would involve an over-reliance on DSM given its deliverability (both volume and schedule) risk, and the consequences of ending up short of supply (BC Hydro Argument, p. 122).

BC Hydro submits that the DSM Plan in Adjusted Option A meets 72 percent of the energy gap in F2020. Because this plan represents “such a significant increase over the level of DSM initiatives of previous years” , BC Hydro considers that the proposed level of savings associated with Adjusted Option A is appropriate, and submits that any amount of DSM above this is considered to be “overly risky” (BC Hydro Argument, pp. 119-120).

BCOAPO submits that the Commission should endorse Adjusted Option A with a “strong indication” to BC Hydro to ramp up its DSM programs. BCOAPO points to BC Hydro’s track-record and contends that it has over-performed and under-spent in the past. BCOAPO submits that BC Hydro’s contention that any DSM plan that exceeded its forecast load-growth would create a net cost to ratepayers should be rejected by the Commission (BCOAPO Argument, pp. 14-15).

CEC submits that BC Hydro did not pursue all cost-effective DSM in its Application, and that BC Hydro’s defense of its Adjusted Option A is a “rationaliz[ation] by suggesting that cost-effectiveness includes the concept of risk and that BC Hydro perceives the risks such that Option B and any other potential DSM would not be cost-effective” (CEC Argument p. 83). CEC argues that by 2016 BC Hydro could increase its cost-effective DSM by about 10 percent or 1,000 GWh/year.

CEC cites BC Hydro’s reluctance to increase its level of expenditure on DSM on the grounds that the level proposed represents a significant increase in expenditure and that it will need to gain experience working at this level before committing to agree that higher levels of expenditure would be cost-effective. It submits that BC Hydro is in effect proposing that the absolute level of DSM expenditure in the next three years is a limit to cost effectiveness. This thereby limits the DSM plan to a three year plan which the CEC submits does not meet requirements of the *Act* (CEC Argument, p. 86).

CEC submits that "It is arguable that had BC Hydro pursued all cost-effective DSM, it may well have been in a position for this LTAP that it need not be considering supply-side resources and acquisition of power in a Clean Power Call." It argues that Commission should direct BC Hydro to increase its investment in DSM initiatives beyond Adjusted Option A in order to aggressively pursue all cost effective DSM in the interest of ratepayers, as an alternative to long-term commitments to higher price supply options, in order to be consistent with the provincial energy policy and the *Act* requirement to pursue all cost effective DSM (CEC Argument, p. 85.)

CEC characterizes BC Hydro as having "positioned itself as the arbiter of when some level of DSM activity above the planned level would be cost-effective" and submits that the appropriate test of cost-effectiveness is "can the DSM initiatives be planned, undertaken and savings delivered at less than the avoided cost of supply with a reasonable degree of certainty?" CEC submits that BC Hydro has not reached the limits of cost-effectiveness (CEC Argument, p. 85).

CEC addresses DSM savings over the next 20 years and submits that it is unreasonable to not assume success in further development of DSM initiatives over that period after BC Hydro's initial couple of years experience with its broader DSM initiatives. The CEC submits it is only reasonable to expect further developments of DSM and that there will be more cost-effective DSM available than is planned for in BC Hydro's Adjusted Option A. The CEC submits the evidence in this hearing overwhelmingly supports the proposition that there will be more DSM savings than have been planned in Adjusted Option A (CEC Argument, p. 87).

CEC analyzes the residential, commercial and industrial components of the two options and submits that by moving about $313 million in expenditures from Option B to Option A ($121 million on residential, $53 million on commercial and $139 million on industrial) and reducing Option A expenditures by taking the same amount from the high cost programs, BC Hydro could, for the same budget, substantially increase the probability of meeting or exceeding its Option A target, and potentially exceed it by a total of 548 GWh/year by F2020 if the savings are proportional to the expenditures (CEC Argument, pp. 94-96).

BC Hydro disagrees with CEC's proposal to scale up certain lower-cost programs to their Option B levels and scale back higher-cost programs from their Option A levels for the following reasons:

- it increases the deliverability risk among the scaled up programs because it moves them closer to the limits of their conservation potential;
- CEC provided no evidence to indicate that the scaled back programs would remain effective or cost-effective; and
- if some of the scaled-back programs are rendered not cost-effective and eliminated, opportunities to participate in DSM would be diminished and with it the DSM Plan's ability to address equity impacts between DSM participants and non-participants.

BC Hydro addressed the CEC submission that BC Hydro did not met the test of pursuing all cost effective DSM in its treatment of "Future Resources" (from F2018 to F2028) in the Base Resource Plan, and submitted that the Future Resources have not been determined to be IPPs, but merely that those resources are included for the purposes of submitting plans to BCTC to ensure adequate transmission plans are in place should IPPs ultimately be selected (BC Hydro Reply, pp. 62-64).

BCSEA developed a concept it terms "DSM Option B Prime" which has the same expected savings as DSM Option A Adjusted, but with the same proposed activities and expenditures as Original DSM Option B. It submits that DSM Option B Prime is "unambiguously superior to DSM Option A Adjusted when evaluated according to the three criteria used by BC Hydro to determine the cost-effectiveness of a DSM portfolio: unit cost, deliverability risk, and diversity" (BCSEA Argument, para. 103-04).

In the final analysis, however, BCSEA "cannot bring ourselves to say that DSM Option A Adjusted is not in the public interest" and so does not argue that the Commission should reject DSM Option A Adjusted and invite or direct BC Hydro to resubmit a DSM Plan and a DSM expenditures schedule along the lines of DSM Option B Prime.

BCSEA rather urges the Commission to conclude that DSM Option A Adjusted is in the public interest as a DSM plan under subsection 44.1 (6) or (7) and as an expenditures schedule under subsection 44.2 (1) (a), but, for the benefit of the development of BC Hydro's next LTAP, BCSEA asks the Commission to comment on whether DSM Option B Prime is cost-effective, is in the public interest, and constitutes "all cost-effective DSM" (BCSEA Argument, para. 108-10).

BC Hydro addresses BCSEA's observation and submits that, by the same logic, a DSM option with the same electricity savings as Adjusted DSM Option A and at two times BC Hydro's planned expenditures would also constitute all cost-effective DSM, and says the question is the value of the incremental expenditures. BC Hydro submits that the proposed expenditures under Adjusted DSM Option A are sufficient to acquire the expected electricity savings and further incremental expenditures run the risk of being ineffective and therefore not cost-effective (BC Hydro Reply, p. 56).

ESVI submits that, based on BC Hydro's consistent over-achievement, the DSM targets used in 2008 LTAP are "too low and should be increased by least 7.6% to accommodate for the tendency of BC Hydro to set their targets too low" (ESVI Argument, p. 3).

BC Hydro observes that "ESVI's assertion is unsupported by evidence in the 2008 LTAP proceeding."

ESVI also provided and cross examined BC Hydro on Exhibit C23-9, a marked-up version of page 101 of 213 of Appendix "K" to Exhibit B-1-1, entitled "Table 1. Cumulative Energy Savings at Customer Meter (GWh/yr)." ESVI's mark-up consisted of calculating by subtraction the incremental annual energy savings provided by BC Hydro over the period F2008 through F2023 for the DSM categories of:

- Codes and Standards plus Rate Structures - Column (i);
- Energy Efficiency Programs, Residential Sector - Column (ii);
- Energy Efficiency Programs, Total - Column (iii); and
- Portfolio Total – Column (iv).

For illustrative purposes, ESVI's results are shown in the following table:

ESVI Incremental Annual DSM Savings (GWh/year) F2008-F2023

GWh/year	Column (i)	Column (ii)	Column (iii)	Column (iv)
F2008	0	42	286	295
F2009	171	57	287	466
F2010	544	96	325	970
F2011	310	146	439	908
F2012	448	124	453	1,206
F2013	-58	92	453	703
F2014	2	88	625	893
F2015	157	92	441	852
F2016	291	106	460	1,156
F2017	200	84	437	1,034
F2018	32	78	244	681
F2019	-4	31	380	790
F2020	79	23	196	652
F2021	39	16	166	395
F2022	-53	13	96	236
F2023	-17	5	61	241

(Source: Exhibit C23-9)

During cross-examination, BC Hydro explained that much of the variability in the results in the various categories was as a result of program introduction dates and decay in the results from those initiatives (i.e. persistence) over time. With respect to the decline in overall results in later years, BC Hydro explained that "…as we go further out into the plan, we've maintained a certain level of activity, but we're starting to come under the phenomenon of the persistence starting to decay and fall off. So, that's what is occurring here" (T13:2467-69).

Later, BC Hydro confirmed that the calculated values in Exhibit C23-9 were before the adjustment to Option A arising from its Evidentiary Update, and that in general, all values would be adjusted downwards by 11 percent to conform to the Evidentiary Update. BC Hydro also reconfirmed that the decay in results in later years was “the decay of the savings from prior periods,” and that “it could be that as we get close to that period that we’ll have new information, and it would allow us to come forward with different DSM initiatives, but we’re too early in the process...to know that with enough certainty to have factored that in at this point” (T14:2735-40).

BC Hydro confirmed that the decay over the last four years of the program to an average of 381 GWh/year savings for those four years from an average of 920 GWh/year savings for the ten year period from F2010 through F2019 cumulated to a net increase in electricity supply required of 2,156 GWh (T14:2736-37). Further, BC Hydro testified that “the decay is factored into the net numbers in the cumulative numbers that we actually do reflect within the load resource balance” (T14:2740).

BC Hydro does not address these matters further in either its Argument or Reply, and limits its submissions in respect of its DSM Plans to the period ending with F2020.

TAN submits that the “soft sources” of DSM BC Hydro is now targeting will be harder to achieve and views BC Hydro’s DSM plan “with a good deal of skepticism” (TAN Argument, p. 4).

IPPBC includes the following table in its Argument to demonstrate that all the DSM components in the Option A portfolio do not show the same degree of cost-effectiveness, noting that Rate Structures are very inexpensive, Codes and Standards are the next least costly, and that programs, as a group, are the most costly per unit of energy saved.

All Ratepayers Costs F2008-F2028 ($ millions)

	Codes & Standards	Rate Structures	Programs	TOTAL
Residential	1,840	34	1,234	3,108
Commercial	325	23	1,815	2,162
Industrial	36	192	2,242	2,470
Portfolio-Level			749	749
TOTAL	2,201	249	6,040	8,489
	26%	3%	71%	100%

(Source: IPPBC Argument, p. 20 derived from Exhibit B-3, JIESC 1.17.5)

IPPBC points out the difficulty of accurately estimating the potential savings from any given DSM measure or combination of measures, and of measuring what actually happened after the fact, because the "unaltered world" no longer exists as a comparator.

IPPBC submits that estimates of the savings that can be achieved by any given program require the program designer to first make informed estimates of several critical determinants, including free riders, free drivers or spillovers, persistence, cross-effects on other energy consumption, and even the energy savings from an individual transaction (IPPBC Argument, p. 20).

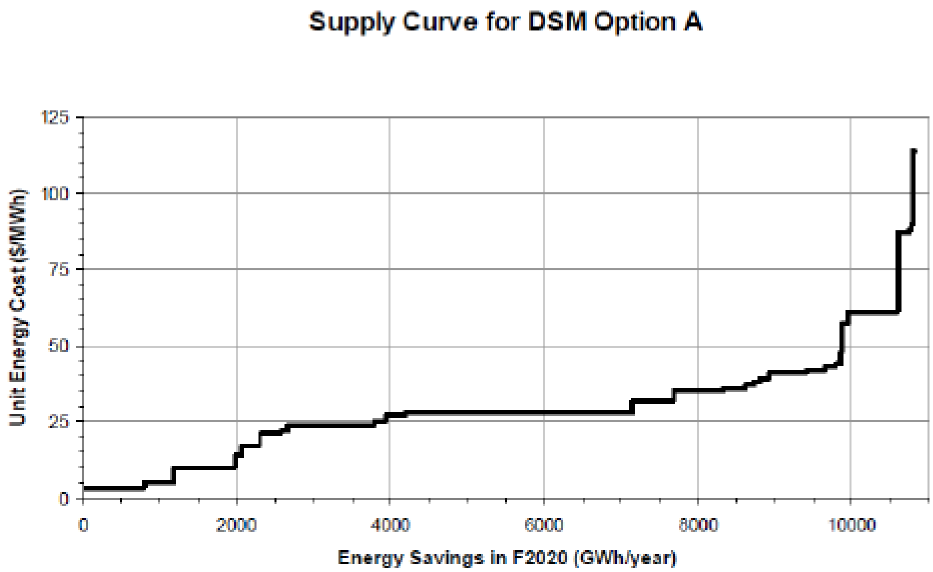
IPPBC submits that if the energy savings that resulted from the long-term elasticity were properly identified and attributed to the Rate Structures instead of to program savings, the result would be that many of the programs would no longer be considered cost-effective.

IPPBC contends that if the long-term elasticity had a value of -0.15, there could be 3,000 GWh that was properly attributable to Rate Structures but was attributed to program energy savings because BC Hydro "elected to deal with a potential double-counting problem by simply omitting to recognize the impact of the consumer price response under Rate Structures. If that much of the savings were reallocated from Programs to Rates, it would effectively double the unit costs of all the programs" (IPPBC Argument, p. 21).

BC Hydro submits that it uses the generally accepted industry standard as a guide for its DSM program evaluations and that its DSM evaluation group is highly respected in the field. BC Hydro states that it follows leading practices for DSM forecasting and evaluation and accounts for applicable risks and uncertainties as appropriate. The low cost of DSM allows it to remain cost-effective despite these uncertainties (BC Hydro Reply, p. 71).

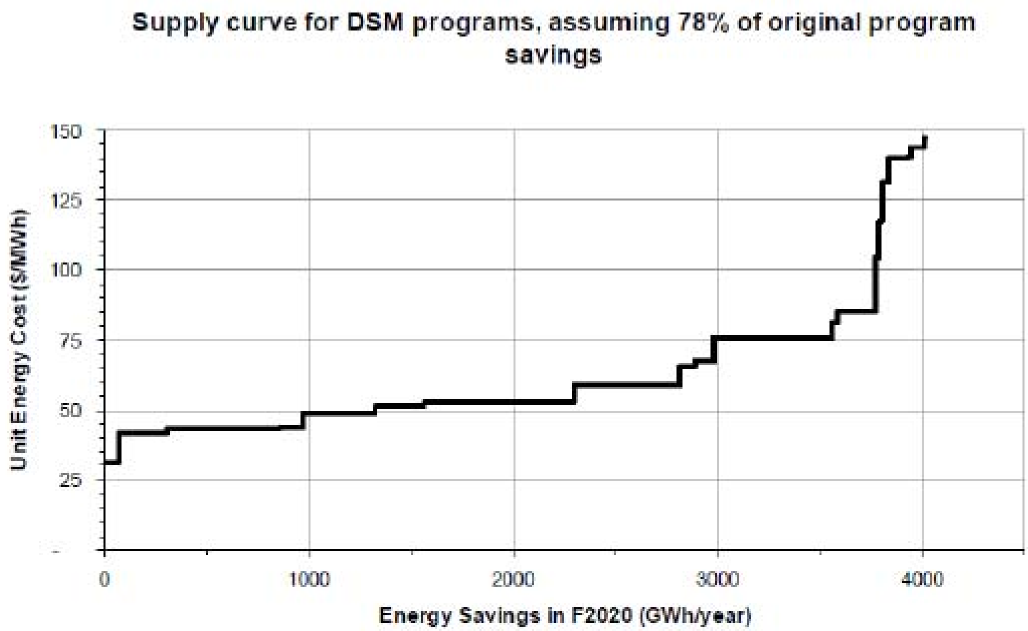
BC Hydro addresses IPPBC's attribution issue and submits that eliminating the long-run elasticity estimate for the purpose of forecasting rate impacts is appropriate because the consumer response to changes in Rate Structures would require other DSM initiatives such as DSM programs or Codes and Standards, which need to be monitored and the savings reported as DSM initiatives pursuant to the *Act*. BC Hydro submits that its separation of short and long-run elasticity was necessary to prevent the double counting of energy savings and to properly allocate those impacts due to DSM programs and Codes and Standards separately from those due to changes in rate levels or Rate Structures (BC Hydro Reply, p. 45).

In its Final Argument, JIESC includes the following table from Exhibit B-68 which it describes as one of two "very telling exhibits" and submits that "Clearly Option A takes up most of the cost effective DSM opportunities available to BC Hydro at this time" (JIESC Final Argument, pp. 20, 22-23).



(Source: Exhibit B-68)

Exhibit B-83 is the second of the two “very telling exhibits” that the JIESC says demonstrates that that there is a very real hard limit to the amount of cost-effective DSM that can be achieved from DSM programs. JIESC submits that a “reasonable interpretation of the graph is that at about 3,800 GWh/year one goes from cost-effective DSM at roughly $80 MWh to cost-ineffective DSM at $140 MWh plus. Clearly at this point alternatives to DSM programs must be found, be they Codes and Standards, Rate Structures within the DSM family, or new resource acquisitions brought in through Resource Smart Projects for [*sic*] IPP calls.” (JIESC Final Argument pp.20-22)



(Source: Exhibit B-83)

BC Hydro submits that Exhibit B-83 was its response to an undertaking requested by IPPBC that depicted the levelized costs of programs under a specific scenario identified by IPPBC, and does not represent BC Hydro's depiction of an expected outcome. Secondly, it argues that JIESC's assertion ignored the following caveats noted in Exhibit B-83 that explain why it might be inappropriate to make decisions based on either the UECs or the adjusted UECs:

- adjusted UECs assume a "worst-case scenario" in which all of the shortfall in DSM savings results from programs;
- the UECs do not include the value of avoided regional transmission or distribution capacity costs;
- the UECs do not reflect the 30 percent benefits added granted to low-income programs by the DSM regulation; and
- the UECs reflect 100 percent of portfolio-level costs being allocated to programs, rather than to both Rate Structures and programs which is BC Hydro's current approach.

(BC Hydro Reply, p. 61)

Commission Determination

The Commission Panel considers that a certain amount of confusion during the hearing was caused by the use of a headline price in the $40-$50/MWh range for the DSM portfolio BC Hydro proposed in contrast to the use of a proxy price for new supply-side power from IPPs in the $120/MWh range, which BC Hydro's witnesses did not contradict.

The Commission Panel further notes that BC Hydro's portfolio approach results in the costs of the programs being spread over savings from Codes and Standards and Rate Structures (neither of which incurs costs of any consequence) and the programs themselves.

The Commission Panel finds that the use of this portfolio cost approach has little value when it is determining the cost-effectiveness of DSM, since it could hardly be said to be in the public interest to approve, by way of illustration only, a DSM program having a UEC of $150/MWh when new supply was available at $110/MWH.

The Commission Panel does not accept BC Hydro's assertion that by meeting more than its load growth with DSM it would impose a cost on its ratepayers, since the portfolio analysis prepared by BC Hydro in Figure 5-14 of Exhibit B-1 only showed that this might happen in extremely remote circumstances.

The Commission Panel notes BC Hydro's attempt to reflect deliverability risk in its DSM program into the levelized price of its programs by using probability analysis. It also notes, however, the absence of comparable analysis by BC Hydro of the economic risk to its ratepayers of committing to long-term new supply. The Commission Panel has no evidence before it as to how a fully risk-adjusted UEC of a DSM program might be directly compared with, say, a fully risk-adjusted UEC of a negotiated EPA from the 2008 CPC.

The Commission Panel notes that subsection 44.1 (8) (c) of the *Act* requires it to consider whether BC Hydro's plan shows that the utility intends to pursue adequate cost-effective demand-side measures, and subsection 4(1) of the M271 permits it to compare the costs and benefits of (i) the demand-side measure itself, (ii) the demand-side measure and other demand-side measures in the portfolio, or (iii) the portfolio as a whole, in determining the cost-effectiveness of DSM.

The Commission Panel considers that within the context of an LTAP, it is appropriate to determine the cost-effectiveness of a DSM Plan by calculating the UEC of DSM programs on a program-by-program basis and to compare the UEC of that program with supply-side alternatives on an equivalent basis.

Since there is insufficient evidence before it of the lowest UEC from the 2008 CPC, the Commission Panel is unable to state with any certainty where "cost-effective" DSM becomes "cost-ineffective" in comparison to any such supply side option.

As noted at Section 6.4.3.2, the Commission Panel also found uncertainty in how such a comparison would be made and requires BC Hydro to address the issue in its next LTAP application.

As noted in Section 1.2 of this Decision, BC Hydro provided its interpretation of the relevant regulatory framework as: "Pursuant to subsection 44.1(2)(b), [BC Hydro] must pursue all cost-effective DSM prior to pursuing any supply-side options, [and] pursuant to subsection 44.1(2)(f), BC Hydro must prove why it cannot fill its entire load/resource gap with DSM only."

For the reasons given, the Commission Panel has concluded that BC Hydro has not met the statutory burden it acknowledged the *Act* requires. Accordingly, the Commission Panel finds that it is unable to determine the DSM Plan as proposed by BC Hydro complies with section 44.1 of the *Act*.

The Commission Panel agrees with CEC and ESVI that BC Hydro's 20-year plan does not reflect the fact that there will be more cost-effective DSM available than is planned for in Adjusted Option A. With particular reference to Exhibit C23-9 and the discussion surrounding it, the Commission Panel finds that BC Hydro has not planned for cost-effective DSM programs beyond 2020, choosing rather to let its Option A Plan "expire," to be refreshed at a later date, yet reflecting the impact of that expiry in its load/resource balance from F2020 onwards.

The Commission Panel has earlier determined in Section 6.2 that BC Hydro's LTAP is deficient in that it fails to recognize and make provision for the requirement for the insurance aspect of self-sufficiency pursuant to SD 10 in a timely fashion ahead of the F2026 deadline for that requirement to be fully met. DSM plays a paramount role in establishing the electricity supply obligation against which that insurance must be quantified. While the Commission Panel does not expect BC Hydro to have fully developed plans for the later stages of the planning period, as a minimum, it requires BC Hydro to establish in its DSM plan the equivalent of the "contingency resources" as it has for the supply side, and put forward its expectations for the results deliverable from those "contingency DSM programs." **Inasmuch as BC Hydro has effectively chosen to truncate its DSM programs in F2020 by letting the impact of those programs progressively decay, the Commission Panel finds that BC Hydro's DSM Plan is deficient.**

6.5 Existing and Committed Resources

This Section of the Decision examines the existing and committed resources BC Hydro identified to meet its electricity supply obligations over the plan period.

6.5.1 Background

BC Hydro sets out the energy capability of the existing and committed resources in its integrated system as follows:

Proposed Existing and Committed Resources (Energy)

(GWh)	F2012	F2017	F2022	F2027
Hydro				
Heritage Hydro	42,565	42,565	42,565	42,565
Resource Smart	412	587	587	587
Total Hydro	42,977	43,152	43,152	43,152
Thermal				
Burrard	3,000	3,000	3,000	3,000
Other	230	230	230	230
Total Thermal	3,230	3,230	3,230	3,230
IPPs				
Pre 2006	7,071	6,880	6,059	6,020
F2006CFT	1,798	1,910	1,910	1,910
SOP	330	436	436	436
Total IPP	9,199	9,226	8,405	8,366
Total	**55,406**	**55,608**	**54,787**	**54,748**

(Source: Exhibit B-12, BCUC 3.269.1)

BC Hydro sets out the capacity of the existing and committed resources in its integrated system as follows:

Proposed Existing and Committed Resources (Capacity)

(MW)	F2012	F2017	F2022	F2027
Hydro				
Heritage Hydro	9,707	9,707	9,707	9,707
Resource Smart	548	636	636	636
Total Hydro	10,255	10,343	10,343	10,343
Thermal				
Burrard	900	900	900	900
Other	51	51	51	51
Total Thermal	951	951	951	951
IPPs				
Pre 2006	656	648	593	584
F2006CFT	111	117	117	117
SOP	30	39	39	39
Total IPPs	797	804	749	740
Total	**12,003**	**12,098**	**12,043**	**12,034**

(Source: Exhibit B-12, BCUC 3.269.1)

6.5.1.1 Heritage Hydro

BC Hydro states that its firm energy capability of its Heritage hydroelectric facilities is 42,600 GWh/year and is consistent with subsection 1(2) of SD 10 which provides that the definition of "firm energy capability" … "must be interpreted for the purposes of [SD 10] so as to be consistent with the fact that, in 2006, the authority's firm energy capability was 42,600 gigawatt hours" (Exhibit B-1, p.2-11).

6.5.1.2 Resource Smart

BC Hydro includes the energy it anticipates from a number of Resource Smart projects, including Aberfeldie, GM Shrum Units 1-8, Revelstoke Unit 5, Cheakamus, and John Hart (Exhibit B-1, p. 2-12).

6.5.1.4 Thermal

BC Hydro states that this category comprises two gas-fired generating stations in its integrated service area, Burrard and a simple-cycle gas turbine ("SCGT") at Prince Rupert. Burrard is considered at greater length below.

6.5.1.5 Independent Power Projects

BC Hydro states that, in addition to 48 EPAs signed prior to 2006, it has estimated the number of EPAs from the F2006 Call that will reach Commercial Operations Date ("COD"), and from its Standing Offer Program ("SOP") approved by the Commission in 2008. In addition, it states it has included energy and capacity from the 2007 EPA with Rio Tinto Alcan (Exhibit B-1, pp. 2-14).
BC Hydro's existing and committed resources projections elicited little or no comment from the Intervenors other than in respect of Burrard, which was the subject of considerable attention.

6.5.2 Burrard Thermal Generating Station

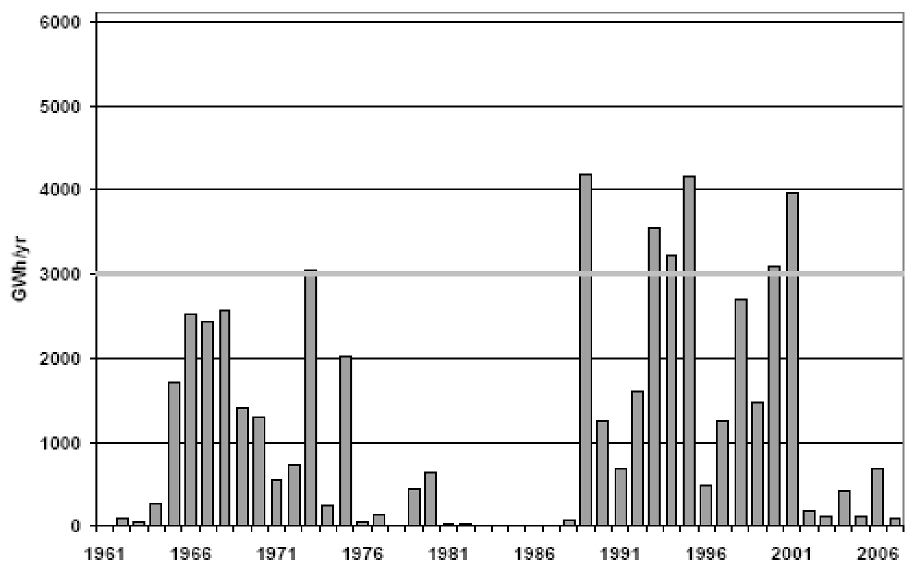
6.5.2.1 Introduction

BC Hydro states that Burrard is its main natural gas-fired thermal generating facility, and that following significant analysis and review since the 2006 IEP/LTAP, it has concluded that it must continue to rely on Burrard for its full capacity of 900 MW to reliably meet its obligations in the Lower Mainland/Vancouver Island ("LM/VI") region at least until 5L83 is in service, including a potential delay to 5L83's in-service date ("ISD") of up to five years to October 2019. BC Hydro states that it has also concluded that an appropriate maintenance program can be implemented to allow it to rely on the plant for 900 MW and 3,000 GWh/year for planning purposes through the planning horizon. This is a change from BC Hydro's position in the 2006 IEP/LTAP which relied on Burrard for planning purposes for 900 MW and 6,100 GWh/year until 2014.

6.5.2.2 History

BC Hydro states that Burrard is a generating station located on Burrard Inlet in the City of Port Moody that consists of six natural gas fired boilers and six turbine generator units, which were placed in service between 1964 and 1975. Although planned and designed for base-load generation, Burrard has rarely been base-loaded as BC Hydro began construction of its hydroelectric facilities on the Peace and Columbia Rivers shortly thereafter. Because of its poor heat rate, Burrard is rarely dispatched, as it is usually more economic for BC Hydro to purchase power in the market.

Figure 5-7 Burrard Actual Annual Generation



(Source: Exhibit B-1, p. 5-25)

6.5.2.3 Capacity

BC Hydro states that the rated capacity of Burrard's six turbine generator units is 920 MW, but that up to 1998, it could not rely on this capacity for planning purposes because of gas supply issues. In the period 2001-2006 BC Hydro converted three of the generator units to synchronous condensers and derated the capacity it could rely on to 450 MW. In the period 2007-2008, BC Hydro returned the three synchronous condensers to generating units, with the result that the capacity it can rely on is currently 900 MW (Exhibit B-1-1, Appendix J1, p.6 of 167).

6.5.2.4 Interior to Lower Mainland Transmission System

Planning for Burrard has to take into account the ILM Transmission System. In its 2006 IEP/LTAP, BC Hydro tied reliance on Burrard to the upgrade of the ILM system, which was forecast to be 2014. Since the 2006 IEP/LTAP proceeding, BCTC has applied for a CPCN for 5L83 to reinforce the ILM. The evidence put forward by BCTC in that proceeding demonstrated that the Lower Mainland/Vancouver Island ("LM/VI") distribution system could not withstand an N-1 event on the ILM and that Burrard would be required to be available until the reinforcement was complete. N-1 is a planning criteria whereby the load must be able to be served when the largest single source of capacity is out of service.

BC Hydro states that although the ISD for 5L83 is scheduled for October 2014, it has nevertheless added a contingency period of 5 years to allow for legal challenges, permitting delays and related occurrences. Burrard must be available to provide what BC Hydro describes as "soft" Reliability-Must-Run ("RMR") capacity to support the ILM network from the present time through to when 5L83 is in-service. BC Hydro does not know of any realistic new capacity supply alternative to Burrard given that there would be significant lead time in implementing any such new resource in the LM/VI region, and that there is a shortfall today absent Burrard being made available to provide RMR.

BC Hydro states that its plan in the eventuality that 5L83 is delayed includes reliance on Burrard and the Canadian Entitlement ("CE") to energy and capacity benefits under the *Columbia River Treaty,* and that reliance on the CE would likely increase if Burrard were to become partially or wholly unavailable (Exhibit B-3, Westpac 1.1.3).

The completion of ILM will not mean that Burrard is no longer required. BC Hydro states that 5L83 will add no generating capacity to its system, and that it will still require Burrard.
(Exhibit B-1, p. 2-22)

6.5.2.6 Energy Capability

BC Hydro states that Burrard's energy capability for planning purposes to date has been set at 6,100 GWh/year, but that it has never been able to "utilize the full energy capability" as a result of a number of factors such as intra-year hydrological variability, actual plant capability and the availability of electricity in the markets creating an operating environment that has not been "conducive to extended high-output operation."

BC Hydro provided an operating pattern for Burrard that it determined using planning capability studies based on Burrard output being displaced whenever its Heritage hydroelectric system and IPP resources produce "secondary" energy (i.e., energy available when water conditions are greater than critical stream flows), but not displaced by non-firm energy from external markets. BC Hydro estimates that Burrard would be expected to run at 6,100 GWh/year for a large part, but not all of a critical water sequence, and that at most the plant would provide approximately 5,000 GWh/year on average through the critical period (Exhibit B-1, p. 5-27).

BC Hydro states that Burrard operates under a number of environmental permits, the two key permits being a Metro Vancouver air emission permit (GVA 0330) and a BC Ministry of Environment ("MOE") effluent discharge permit (PE-07178) (Exhibit B-1-1, Appendix J3, p. 29 of 250). In 1994, Metro Vancouver revised its permit requirements and BC Hydro was obliged to install silicon control rectifiers ("SCR") on its boilers between the years 1995-2000. BC Hydro states that a number of upgrades were carried out at the Station in this period.

The effluent discharge permit limits Burrard's ability to discharge its cooling water into Burrard Inlet when water temperatures at the end of the cooling water outfall exceed 27°C and can limit

Burrard's output to four units during hot weather in summer months (Exhibit B-1-1, Appendix J1, p.28 of 167).

6.5.2.7 Consultants' Studies

BC Hydro states that it undertook and filed "significant new evidence" completed by third-party consultants on Burrard as part of its review and analysis and in support of its conclusions with respect to Burrard's future. The evidence included:

- "Condition Assessment & Alternative Configuration Study" by AMEC Americas Limited ("AMEC") being a study of the condition of the existing configuration and a study of possible reconfigurations of a redeveloped plant; and
- "Consent to Operate Risk Analysis" by RWDI AIR Inc. ("RWDI") being a study of the existing configuration and "Permitting Requirements for Rebuilding" being a study of possible reconfigurations of a redeveloped plant.

(Exhibit B-1-1, Appendices J1 to J4)

6.5.2.7.1 The AMEC Report

The AMEC Report dated April 22, 2008 sets out the tasks it was retained to undertake. Task 1 was to prepare a report documenting a reasonable view of current equipment condition, life expectancy, perceived catastrophic failure risks and options. This included items related to operational constraints in order to prevent equipment failure, safety issues and any potential breach of Burrard's air emission, liquid effluent and other environmental permits.

This condition assessment provides the background to Task 2, being the recommended maintenance programs and year-by-year budget estimates for three operating scenarios specified by BC Hydro for a 20-year life to 2028. The scenarios are:

1) continuing to operate in the current peaking and synchronous condenser mode;
2) energy and capacity facility operating at 3,000 GWh/year; and
3) energy and capacity facility operating at 6,000 GWh/year.

The study report also includes:

- an estimate of air emissions (including GHG) by year for each of the three scenarios for the next 20 years; and
- documentation of any past maintenance deficiencies.

(Exhibit B-1-1, Appendix J 1, p. 14 of 167)

AMEC summarized its findings on Burrard's condition stating that:

> "Burrard TGS appears to be in reasonably good condition for its age of 32 to 40+ years. This is largely due to: a) its limited actual use, b) the implementation of the previous Burrard Upgrade Project (BUP), and c) the manner in which its management and staff have managed the many changes in role and direction of the plant, while following industry and vendor directed practices for maintenance and operations, within the budget constraints imposed by the plant's role." (Exhibit B-1-1, Appendix J 1, p. 6 of 167)

So far as Task 2 is concerned, AMEC reported that:

> "Cost Implications of Scenarios 1, 2 and 3: Burrard TGS is NOT at present in a condition consistent with the Scenarios 1, 2 and 3 set out above where 900 MW of generation capacity is consistently critical over the next twenty years (an "N+0, where N=6" role). Without significant investment in detailed inspections in the next two years and procurement of critical spares, extended single unit outages (and possibly multiple unit outages), due to major critical equipment failures, is a reasonable position in the next 2 to 5+ years (depending on the scenario)."
> (Exhibit B-1-1, Appendix J 1, p. 8 of 167)

AMEC devises the following operating pattern for the six units at Burrard to match the three scenarios:

	Units 1 - 3	**Units 4 - 6**
Scenario 1	75 GWh/unit/yr(1)	120 GWh/unit/yr
Scenario 2	727 GWh/yr(2)	2,248 GWh/yr(3)
Scenario 3	All units need to be run at 75 – 77% annual capacity factor(4)	

(1) These units would also run between 1,700 and 3,100 hours/year as synchronous condensers.
(2) These units would also run for 1,600 hours/year as synchronous condensers.
(3) The units would not run in the summer months.
(4) Due to cooling water limitations, output was limited to ~5,800 GWh/year.
(Source: Exhibit B-1-1, Appendix J 1, pp. 82-83, 89 & 95 of 167)

AMEC states that Scenarios 1, 2 and 3 require high levels of availability and reliability for 20 years, and opines that Burrard is currently not well positioned as such a high reliability capacity (85% + availability at 900 MW) or energy (3,000 GWh/year to 6,000 GWh/year) producer (as an “N+0” facility) for the next twenty years. AMEC states that Burrard will require significant re-investment to achieve those targets in the short or long term, and that the first priority to accurately rationalize these investments is a detailed condition assessment program of major potentially end-of-life equipment (steam turbines, generators, transformers), as well as almost immediate major re-investment in controls and protection systems for Units 1 to 3, in major equipment spares and possibly in major equipment replacement (depending on condition assessments and detailed life role assessments) (Exhibit B-1-1, Appendix J 1, p. 102 of 167).

AMEC identifies three types of capital expenditures: base, probable, and availability capital, and estimates that the requirements over the next 20 years will be as follows:

($million)	Scenario 1	Scenario 2	Scenario 3
Base Capital	134.7	177.3	192.2
Probable Capital	69.6	62.9	73.9
Availability Capital	61.8	70.4	75.6
Total	266.1	310.6	341.7

(Source: Exhibit B-1-1, Appendix J 1, p.107 of 167)

AMEC describes the expenditure categories as:

- Base Capital - expected necessary to meet the requirements of the scenarios;
- Probable Capital - major capital items expected to meet scenario requirements, but whose certainty or timing is uncertain and subject to key future decisions and inspections, and operations and maintenance items caused by likely failures or uncertain replacement; and
- Availability Capital - to meet scenario requirements with minimal delays due to manufacture lead times (major spare equipment primarily) where certainty is not clear and subject to key future decisions and inspection assessments.

(Exhibit B-1-1, Appendix J 1, p.42 of 167)

BC Hydro testified that it plans to determine the expenditures necessary and submit them for approval of its Board of Directors and of the Commission (T6:852, T6:948).

In BC Hydro's submission, its plan to rely on Burrard will entail both sustaining capital and O&M costs, and while the exact costs cannot be determined at this time, the Commission should expect the costs to be in the order of the AMEC estimates set out above. At a minimum, BC Hydro must incur costs to ensure 900 MW of capacity is reliably available (BC Hydro Argument, p.158).

6.5.2.7.2 Examination of Alternatives for Burrard

BC Hydro states that it also retained AMEC to examine alternatives for rebuilding Burrard, which it describes as "alternative configurations," and included rebuilding with new SCGT and/or combined-cycle gas turbine ("CCGT") unit:

BC Hydro concludes that the rebuilding options for Burrard are either infeasible or both higher cost and higher risk than relying upon Burrard in its current configuration. To ensure that Burrard is available to provide the required capacity, BC Hydro is planning actions that minimize the risk of the plant being unavailable or available at a reduced capacity. These actions include:

- reducing the planned firm energy commitment to 3,000 GWh;
- funding and implementing the refurbishment plan as proposed by AMEC for the 900 MW 3,000 GWh reliance on Burrard; and
- delaying any potential plans to rebuild the plant that may raise either social licence or permitting issues until 5L83 is in place.

(Exhibit B-1, p. 5-46)

While no Intervenor contested BC Hydro's conclusion that this is not the appropriate time to consider re-developing the Burrard site with modern natural gas-fired generation (BC Hydro Argument, p. 139), the level at which Burrard should be relied upon for planning purposes was a matter of considerable contention in the proceeding as discussed later in this Section.

6.5.2.7.3 The RWDI Report

RWDI's report is dated June 4, 2008 and is entitled "Burrard Thermal Generating Station – Consent to Operate Risk Analysis." In the Executive Summary, RWDI states that in partnership with Communicate Public Affairs, it was retained by BC Hydro to provide an assessment of the risks to Burrard's consent-to-operate (i.e. risks to its "social licence") for the next twenty years as currently configured under the following planning scenarios:

1) Burrard in its current peaking function of approximately 500 GWh/year;
2) Burrard as a base-load plant for approximately 3,000 GWh/year; and
3) Burrard as a base-load plant for approximately 6,100 GWh/year every year (Scenario 3A), and Burrard as a base-load plant with a pattern during a 60-year period of 6,100 GWh/year for four low-water years, 5,000 GWh/year for one low-water year and no more than 3,000 GWh/year for the remaining 55 years(Scenario 3B).

RWDI notes that these scenarios do not represent physical changes to the plant configuration, but represent changes to how the plant is operated, with the objective of informing BC Hydro whether the risks are likely to manifest themselves in demands that Burrard be shut down, in operational constraints, or in additional costs.

For the purposes of its report, RWDI describes "social licence to operate" as: "The notion of licence to operate derives from the fact that every company needs tacit or explicit permission from Governments, communities and other stakeholders to do business."[1] (Exhibit B-1-1, Appendix J 3, p. 4 of 250)

RWDI discusses the Lower Fraser Valley ("LFV") airshed and states that, in the 1980s, the LFV was identified by the Canadian Council of Ministers of the Environment ("CCME") as one of three areas in Canada requiring the implementation of remedial action plans due to non-attainment of the federal maximum acceptable objective for ground-level ozone. Furthermore, the LFV does not yet fully comply with the CCME Canada-wide Standard ("CWS") for ground-level ozone.

Table 3-4 of RWDI's Report compares the estimated common airborne contaminants ("CAC") emissions under the three scenarios with Burrard's current permit and notes that the estimated NO_x emissions for scenarios 3A and 3B are less than Burrard's historical emissions prior to the installation of SCR systems. (Exhibit B-1-1, Appendix J 3, p. 35 of 250)

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[1] Porter, Michael E. and Kramer, Mark R. "Strategy and Society: The Link Between Competitive Advantage and Corporate Social Responsibility" Harvard Business Review Volume 84, Number 12 pp78-92

RWDI advises that in 2005, Metro Vancouver promulgated new ambient air quality objectives that are more stringent than provincial and federal objectives for most of the CACs. The most striking difference is for one-hour nitrogen dioxide (NO_2) where the Metro Vancouver objective is half the most stringent federal level. The difference in the Metro Vancouver and federal fine particulate matter ($PM_{2.5}$) criteria is smaller but it will be more difficult to achieve than the NO_2 target. RWDI considers that these changes in ambient criteria in Metro Vancouver could be significant for Burrard because voluntary and mandatory curtailment requirements are tied to monitored concentrations of NO_2 and PM relative to ambient criteria.

RWDI states that BC Hydro commissioned it to perform a dispersion modeling study of existing operations as well as for Scenarios 2 and 3, for due diligence purposes and to supplement the social licensing study.

RWDI states that the results of the 2008 dispersion modeling study of Burrard's NO_x emissions indicate that exceedances of Metro Vancouver's new ambient air quality objective for annual NO_2 are not expected. Exceedances of the new one-hour objective are predicted to occur in the near vicinity of Burrard for Scenarios 1 and 2 as well as start-up and shut-down operations. The exceedances are due to emissions from the auxiliary boiler which would not operate under Scenarios 3A and 3B and therefore no exceedances are predicted for these scenarios when up to the 99th percentile observed ambient concentration is added to maximum predicted concentrations.

RWDI notes that the auxiliary boiler never operates during Scenarios 3A and 3B because either Unit 5 or Unit 6 is always operating and therefore can supply the required steam to Imperial Oil. When up to the 99th percentile background concentration is added, the fact that exceedances are only predicted for scenarios requiring the auxiliary boiler indicates that the exceedances are due to emissions from the auxiliary boiler. This hypothesis was tested by modelling emissions from the auxiliary boiler alone and exceedances were predicted (Exhibit B-1-1, Appendix J 3, p 46 of 250).

RWDI addresses the existing MOE effluent discharge permit and states that it “is deficient for operating Burrard at full load throughout the year. Engineering calculations based on historical records of sea water temperature indicate that the capacity of Burrard is limited from May to November” (Exhibit B-1-1, Appendix J 3, p. 8 of 250).

A section of RWDI’s report (Exhibit B-1-1, Appendix J 3, pp. 47 to 67 of 250) addresses public perception to emissions and the issue of Burrard’s “social licence”. RWDI points out that under Scenarios 3A and 3B, Burrard would be the largest point source of GHG emissions in the province (and second largest under Scenario 2) and the second largest point source of NO_x under Scenario 3 (Exhibit B-1-1, Appendix J 3, p. 82 of 250).

RWDI summarizes the debate on the generation of natural-gas fired electricity in the LFV that took place before the National Energy Board concerning the Sumas Energy application in 2002 for approval to construct a transmission line, and states that operating generating facilities requires a social licence, that securing a social licence for new projects in the Lower Mainland and Fraser Valley can be challenging, and that maintaining an existing social licence can also prove challenging and requires more than providing jobs, investing capital, purchasing goods and doing business every day; a willingness to engage the public in an ongoing way to build awareness and acceptance of industrial operations is also needed. In the absence of information, the public frequently defaults to a worse-case scenario, especially when there is a debate among technical experts about the merits of the project.

RWDI concludes that BC Hydro’s efforts to engage the public in discussion about the operation of Burrard, initiated at the time of the Burrard Upgrade Project, appear to have been effective in maintaining public consent to operate. This is evidenced by media comments made by the current Mayor of Port Moody in support of Burrard, by the ongoing willingness of local residents to participate in Burrard’s Community Liaison Committee, and by the recent (January 8, 2008) resolution by Port Moody Council to “oppose all efforts to close this important and strategic asset” (Exhibit B-1-1, Appendix J 3, p.11 of 250).

RWDI also comments on BC Hydro's response to public complaints about Burrard's "noise, light pollution and aesthetics," noting that silencers were installed on all units, lighting at the plant was upgraded, trees were planted along the shoreline, buildings were painted green and visible rust was painted over (Exhibit B-1-1, Appendix J 3, p.29 of 250).

6.5.2.8 BC Hydro's proposal of 3,000 GWh/year for Planning Purposes

BC Hydro seeks the Commission's endorsement of its plan to rely on Burrard for 900 MW of dependable capacity and 3,000 GWh/year of firm energy ("Endorsement (iii)").

BC Hydro states that its decision to rely on Burrard for planning purposes for 3,000 GWh/year required professional judgment, and in its Argument addresses the issue along the following lines:

- technical assessment;
- social licence analysis;
- regulatory and policy framework; and
- operational feasibility.

(BC Hydro Argument, pp. 139-154)

6.5.2.8.1 Technical Assessment

BC Hydro submits that while AMEC found that 6,000 GWh/year was feasible as long as the required investments are made in the plant, AMEC had also noted that the plant will be between 50 and 60 years old at the end of the planning period which BC Hydro views as "placing an unrealistically high expectation on Burrard's long-term availability" (BC Hydro Argument, p. 140).

6.5.2.8.2 Social Licence Analysis

BC Hydro submits that its choice of 3,000 GWh/year was based on its analysis of "social licence risk," and that while 3,000 GWh/year has "some social licence risk and that risk is appropriate to take; moving above 3,000 GWh/year becomes increasingly risky (both probability and consequences but particularly because of the consequences) of loss of social licence" (BC Hydro Argument p. 141). BC Hydro testified to the risk as follows:

> "And if we rely, if we try and move the reliance from 3,000-4,000, we think we're incurring a higher risk to our social licence. And if you look at the consequences of that risk if we're not able to – if we try to go from 3,000 to 4,000 and in the course of doing so we lose the 3,000 and we're pushed down to say 600, the costs of that are quite significant" (T7:1062-63).

6.5.2.8.4 Regulatory and Policy Framework

BC Hydro considered the impact of government policy on its choice of 3,000 GWh/year, and sets out its view on SD 10 and Burrard where SD 10 obliges the Commission in regulating BC Hydro to use the criterion that BC Hydro is to achieve energy and capacity self-sufficiency by "becoming capable of" meeting by 2016, and each year thereafter, its electricity supply obligations solely from electricity generating facilities within BC. BC Hydro observes that the phrase "capable of" is not defined in SD 10. BC Hydro submits that for Burrard to be "capable of" meeting BC Hydro's electricity supply obligations, it must:

- have the technical ability to meet BC Hydro's electricity supply obligations; and
- have the ability to be permitted, or the ability to maintain existing permits

BC Hydro addresses the technical ability and states that if a particular facility can not run due to its age, it is not capable of meeting its electricity supply obligations, and that relying on Burrard for 900 MW and 3,000 GWh/year for planning purposes "would be nearer to the high end of historical operating experience for Burrard" and would be "more technically challenging to ensure reliable operation". In addition, relying on Burrard for 900 MW and 3,000 GWh/year will entail sustaining capital expenditures recommended by AMEC for the years 2010 to 2012 in the range of $55 - $127 million, which BC Hydro believes will make Burrard capable of delivering 3,000 GWh/year.

BC Hydro addresses permitting ability and states that for Burrard, which is situated in the Lower Mainland, the issue is whether there is permitting and social licensing risk if BC Hydro were to run Burrard at 3,000 GWh/year, and that the RWDI report concluded that the existing social licence could accommodate a change to increase expected annual operations to a base-load facility for approximately 3,000 GWh/year (Exhibit B-3, IPPBC 1.7.1).

BC Hydro further states that the long-term viability of displacing Burrard by non-firm sources (domestic or imports) is not just an economic dispatch consideration, pointing out that if BC Hydro were to plan to rely on the firm energy capability of Burrard without making the investment necessary to be able to reliably operate up to that level of dependable capacity and firm energy reliance, it would be contrary to the BC Government's intent of self-sufficiency as embodied in SD 10. In addition, BC Hydro notes that if the firm energy reliance on Burrard were materially above BC Hydro's long-term expected operation of that facility, while relying on material amounts of non-firm import energy (energy that does not meet similar GHG requirements compared with energy that would have otherwise been generated in the Province to make up the difference), use of such imports would avoid the intent of the BC Climate Action Plan.

BC Hydro submits that any resource planning strategy that is based on avoiding the intent of either SD 10, or the Climate Action Plan and related legislation, as would be the case if it were to rely on Burrard for more than 3,000 GWh/year and operating the plant on a minimal basis while relying on import markets to make up the difference, is not expected to be sustainable (Exhibit B-3, IPPBC 1.7.1).

With reference to whether SD 10 would change the way Burrard was operated, BC Hydro testified that the operations will not change "before or after 2016. The operations will operate as it operates, based on economic dispatch" (T7:1063).

BC Hydro submits that the 2007 Energy Plan specifically includes the Province's desire to have Burrard phased out. Policy Action No. 22 states:

> "22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may retain Burrard for capacity purposes after 2014.
>
> "As a part of it Integrated Electricity Plan, BC Hydro has a plan to replace the firm energy from Burrard Thermal by 2014. The proposed approach by BC Hydro is consistent with Government's desire to see Burrard Thermal phased out. The government recognizes that the value of the capacity and voltage support provided by Burrard Thermal may warrant continuing to keep Burrard Thermal available if needed for peaks in demand (for example, resulting from cold winter weather, Christmas lighting, to deal with other resources being unexpectedly unavailable, etc.). These may continue to be appropriate longer term roles for Burrard if that Burrard Thermal continues to be a cost effective voltage support and capacity resource" (Exhibit B-1-1, Appendix B1, p. 57 of 84).
>
> A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia. Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run.
>
> However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations. By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise" (Exhibit B-1-1, Appendix B1, p. 17 of 84).

BC Hydro’s President and policy witness testified “I don't read this that government is saying that's what we must do. In other words, I read this as a carefully worded statement that gives us some flexibility” (T4:398).

6.5.2.8.5 Operational Feasibility

BC Hydro concludes that it is operationally feasible to rely on Burrard only for up to 3,000 GWh/year rather than its 6,000 GWh/year design capability. BC Hydro acknowledges that this conclusion was not derived from simple factual analysis and includes its professional judgment and careful consideration of context. On the basis of this approach, BC Hydro considers that further decreased reliance on Burrard below the level of 3,000 GWh/year (such as 2,000 GWh/year) would result in a corresponding decrease in operational risk. Conversely, operational reliance above the 3,000 GWh/year would increase the corresponding risk. BC Hydro further submits that it considers 4,000 GWh/year reliance to incur marginally more risk beyond 3,000 GWh/year while 6,000 GWh/year represents a substantially greater risk.

BC Hydro uses the expression “operationally feasible” as referring to the long-term sustainability of relying on Burrard.

> “BC Hydro concludes that planning to rely on Burrard for 3,000 GWh/year of firm energy is what is operationally feasible. Any resource planning strategy that is based on avoiding the intent of either SD 10, or the Climate Action Plan and related legislation, as would be the case if BC Hydro were to rely on Burrard for more than 3,000 GWh/year and operating the plant on a minimal basis while relying on import markets to make up the difference, is not expected to be sustainable.” (Exhibit B-3, IPPBC 1.7.1)

In this context, BC Hydro submits that “operationally feasible” is the sustainable level of reliance on Burrard for dependable capacity and firm energy, and embodies the risk (probability and impact) that all or a portion of the plant could not be relied on because of the possibility of it becoming unavailable in whole or in part as a result of technical, social licence or economic reasons (Exhibit B-4, BCUC 2.215.2).

BC Hydro addressed how it would actually dispatch Burrard during the planning period and stated that:

> "The actual expected operation of Burrard is comprised of two major components: (i) operation for system reliability and support, including winter peaking capacity operation to serve peak system load, RMR capacity operation to support the ILM network until 5L83 is in service, operation for the provision of operating reserves, operation to provide reactive power support and operation to support the Heritage hydroelectric system under low water conditions; and (ii) economic dispatch to optimize system operating costs."

BC Hydro states that its portfolio analysis in the 2008 LTAP models the economic dispatch of generation needed under average water conditions to meet load requirements. This analysis does not explicitly model expected dispatch for system reliability and support or the impacts of variable Heritage hydro inflows. As a result the model does not provide the type of analysis necessary to develop expected frequency distributions of actual expected output of Burrard.

Further BC Hydro states that the annual energy output from Burrard, as modeled in the 2008 LTAP studies showed essentially zero GWh/year economic dispatch in all portfolios and scenarios, even when the simulation of Burrard was hypothetically extended to 6,000 GWh/year.

BC Hydro does not expect the actual future operating level of Burrard to be essentially zero GWh/year as long as the plant is being depended on as a source of dependable capacity, firm energy and associated system support service. For system reliability and support operations, an estimate of 600 GWh/year for Burrard energy production has been assumed excluding any economic dispatch component. Actual Burrard operations for system reliability and support may be higher or lower depending on a number of varying factors, such as system peak loads, hydrology and reservoir levels, unit outages, operational constraints and length of time the plant is required to support ILM transmission shortages through RMR operation. Its operation will also tend to be higher if GHG offsets are required on imports.

To approximate the percentage of Burrard's firm energy contribution under the average water conditions that have been modeled, BC Hydro rated, for each portfolio in the 2,000 to 4,000 GWh/year range, the aggregate quantities of each of the three non-firm resources and determined the following quantities from the simulated results:

- the aggregate amount of non-firm energy from the Heritage hydroelectric resource would range from 44 to 53 percent;
- the aggregate amount of non-firm energy from existing and new IPP resources would range from 19 to 27 percent; and
- the aggregate amount of discretionary imports from external markets would range from 25 to 34 percent.

(Exhibit B-3, BCUC 1.102.1)

BC Hydro testified that in an average water year, BC Hydro would tend to have non-firm hydro, either Heritage or IPP, and in a critical water sequence BC Hydro would "be looking to the market, and if the market prices were adverse then we'd be running Burrard" (T7:1064). Finally BC Hydro testified that "we make the assumption that the planned reliance on Burrard has no connection to the actual operation" (T7:1125).

6.5.2.9 Cost Implications

BC Hydro states that the present value of the portfolios it examined that analyzed Burrard's firm energy capabilities at 2,000 to 6,000 GWh/year was as follows:

Table 5-8 (amended) PV of Portfolios analyzing a range of Burrard Firm Energy Capabilities

Gap	Cost of Thermal Gas	GHG	Likelihood	Burrard Firm Energy per Year 2000	3000	4000	6000
	Low	Low	0.6%	11,593	11,069	10,855	10,207
	Mid	Mid	31.0%	11,477	11,075	10,858	10,354
Mid	Mid	High	13.4%	11,770	11,317	11,087	10,500
	High	Mid	38.8%	11,927	11,590	11,349	11,005
	High	High	16.3%	12,016	11,664	11,424	11,079
Weighted Present Value				**11,779**	**11,403**	**11,171**	**10,743**

(Exhibit B-3, BCUC 1.102.1)

The PV difference between 3,000 GWh/year and 4,000 GWh/year is $232 million, that between 3,000 GWh/year and 6,000GWh/year is $660 million.

BC Hydro testified that the incremental operating and maintenance expense and capital cost of operating Burrard at 6,000 GWh/year compared to 3,000 GWh/year would be in the range of $31 to $35 million per year (T7:1061).

6.5.2.10 Views of the Intervenors

A number of Intervenors expressed their views on BC Hydro's selection of 3,000 GWh/year for planning purposes reliance at Burrard. The Intervenors' arguments are reviewed as follows:

- those who generally support BC Hydro's proposal (JIESC, BCSEA, ESVI and TAN);
- IPPBC which contends that Burrard cannot be relied upon;
- those which advocate reliance on 4,000 GWh/ year(BCOAPO and CEC); and
- COPE which advocates reliance on 6,000 GWh/year.

JIESC submits that 3,000 GWh/year is "an easily achievable level" and that while "there are strong arguments in favour of a higher level at 4,000 or even 6,000 GWh…[it] is, for the time being, prepared to accept BC Hydro's 3,000 GWh as reasonable" (JIESC Argument, p. 33).

ESVI submits that BC Hydro should calculate the amount it proposes to rely on Burrard for planning purposes by filling the load resource gap first from ESVI's enhanced DSM option, then from the 2008 CPC at 2,100 GWh/year and lastly rely on Burrard for the balance, which ESVI submits will be less than BC Hydro's recommended 3,000 GWh/year (ESVI Argument, para. 6.4).

BCSEA supports BC Hydro's proposals regarding Burrard, specifically retaining Burrard's capacity at 900 MW and relying on Burrard for 3,000 GWh/y for planning purposes. BCSEA strongly endorses the view that the social licence for the continued operation of Burrard is tenuous and potentially vulnerable. "Any attempt to 'ratchet up' Burrard's energy reliance beyond 3,000 GWh/year on the basis that it would be 'only for planning purposes' and would 'not actually be used' would quite properly be viewed with considerable suspicion by many of the stakeholders associated with Burrard" (BCSEA Argument, para 123-24).

TAN welcomes BC Hydro's "social licence policy" and urges the Commission to give this doctrine its "full endorsement" (TAN Argument, p.10).

IPPBC made a number of submissions concerning Burrard. It first addresses the 2007 Energy Plan and the Shareholder's Letter of Expectations and submits that "BC Hydro is not advancing a replacement proposal for the firm energy from Burrard as it is mandated and obliged to do in accordance with the Shareholder's letter and is in contravention of it," and that BC Hydro's proposal for Burrard is "completely contrary to the provisions of the 2007 Energy Plan" (IPPBC Argument, pp. 30-31).

IPPBC further submits that at present "Burrard is not in a condition consistent with Scenarios 1, 2 or 3," and notes that the expenditures AMEC considered necessary to put it in such a condition are only estimates which needed to be firmed up by equipment inspection and spares procurement, and the program taken for approval by BC Hydro's Board of Directors in the fall of 2009 and return[ed] to the Commission for "a different regulatory process."

IPPBC submits that BC Hydro cannot include Burrard in its Base Resource Plan ("BRP") up to 2019 or beyond and that alternatively, the Commission should reject the inclusion of Burrard in BC Hydro's existing and committed resources until the Commission has concluded its review of a CPCN to carry out the work required by the AMEC Report (IPPBC Argument, p. 33).

IPPBC addresses SD 10 in the context of Burrard and submits that even if BC Hydro made the necessary expenditures to be able to rely on Burrard for planning purposes, it would rarely be economic to dispatch with the result that non-firm Heritage hydro would be brought through the "back door," as would imports (IPPBC Argument, p. 38).

IPPBC addresses BC Hydro's social licence at Burrard and submits that BC Hydro becomes "at cross-purposes with itself" because once it starts to allay public concerns by arguing that its actual operation "won't be nearly as high as its planned operations, it subverts the intent of SD 10, and the policy actions of the 2007 Energy Plan and the Shareholder's letter" (IPPBC Argument, p. 37).

BC Hydro responds to IPPBC's position that BC Hydro must first demonstrate that the plant is technically capable of operating at the energy and capacity levels set out in the LTAP and describes the position as "quite frankly not credible or workable." noting that where Burrard's capacity is being relied on is in the capacity load/resource balance, and that BC Hydro "has no alternative but to rely on that capacity for planning purposes today and for every day at least until 5L83, or some other option in the LM which could provide similar services, is in service" (BC Hydro Reply, p.74).

BCOAPO addresses Burrard under the issue of GHG offsets and considers whether the cost of Burrard's output with the cost of offsets at $300 per ton would be cost effective when compared to purchases from IPPs and imports, and submits that the Commission should require BC Hydro to produce an economic evaluation of increasing reliance on Burrard for planning purposes from 3,000 GWh to 4,000 GWh/year prior to approving any new EPAs (BCOAPO Argument, p. 13).

CEC notes that BC Hydro did not "look at or analyze a scenario of 4,000 GWh/year" and submits that the "maximum practical flexibility of Burrard" should be preserved and that the evidence points to the level of that flexibility being 4,000 GWh/year (CEC Argument, pp. 127-128).

CEC addresses Burrard and SD 10 and submits that BC Hydro is in error in including economic capability in its attempt to define the words "capable of" in SD 10 and submits that SD 10 was not intended "to imply any economical criteria" and that "the intent of SD 10 should be determined by technical and legal capability and that the running of Burrard should be economical for the BC Hydro electric system" (CEC Argument, pp. 129-130).

CEC submits that "Burrard's role in the BC Hydro electric system should be planned to provide VAR support for the system, 900 MW of capacity, 3,000 GWh/year of energy normally, 4,000 GWh/year of energy in circumstances requiring 1,000 GWh/year of additional flexibility and 3,000 GWh/year of insurance capability if and when needed in rare circumstances (CEC Argument, p. 135).

BC Hydro addresses these Intervenors' support of 4,000 GWh/year and points to the testimony of its President, one reference being "a push to 4,000...can't really be justified...a challenge to government policy that we shouldn't be making" (T4:521) and the second made in reference to its Evidentiary Update that "there was no event relating to Burrard that would have led us to change the 3,000 number" (T4:521; BC Hydro Reply, p. 82).

COPE submits that "BC Hydro's proposed plan to downgrade its planning reliance on Burrard to 3,000 GWh/year should not be endorsed by the Commission...[and] that the Commission ought to reject BC Hydro's Plan to rely on 3,000 GWh/year for planning purposes and recommend that reliance on Burrard for up to 6,000 GWh/year for planning purposes (certainly up to 2016 and at least for as long as it is retained for capacity and system stability purposes) would be appropriate and in the public interest at this time" (COPE Argument, para. 62-63).

COPE submits that the technical feasibility of 6,000 GWh/year reported by AMEC is “determinative of this issue” (COPE Argument, para. 75).

COPE addresses the social licence and submits that it is not a strict legal requirement and that the only requirements binding on BC Hydro are the various statutory, regulatory and permitting regimes. These do not include public opinion. COPE notes that “reliance on Burrard at 6,000 GWh would in fact represent no material change from the current or past planning assumptions for Burrard” and submits that any misconception in the public’s view can be proactively addressed by BC Hydro’s stakeholder engagement management (COPE Argument, para. 80-87).

COPE examines the 2007 Energy Plan and submits that reliance on 6,000 GWh/year would not be inconsistent with it, but that in any event energy policy “cannot trump or circumvent legal requirements” and that the 2007 Energy Plan simply states that the BC Government supports BC Hydro's proposal to replace Burrard with other firm supply. COPE further submits that the proposal referred to was made by BC Hydro in the 2006 IEP/LTAP proceeding, and was rejected by the Commission. The 2007 Energy Plan also states that BC Hydro may choose to retain Burrard for capacity purposes after 2014, and COPE cites the testimony of BC Hydro’s President that the language used in this part of the 2007 Energy Plan was intended to give BC Hydro some flexibility with how it addressed Burrard (COPE Argument, para. 97).

In addition, COPE submits that a number of factors warrant continued reliance on Burrard for 6,000 GWh/year, including:

- the need to ensure reliable capacity for VI/LM to at least 2019;
- the fact that reliance on 6,000 GWh/year will not affect the actual operating level of Burrard any more than reliance at 3,000 GWh/year; and
- the significant potential cost savings available to BC Hydro’s ratepayers which COPE identifies as having a PV of $660 million (COPE Argument, para. 91-100).

COPE addresses SD 10 and notes that BC Hydro's interpretation of self-sufficiency is flawed, as the AMEC Report makes it clear that given the necessary capital expenditures Burrard will be technically capable of operating at 6,000 GWh/year, and BC Hydro currently holds the necessary permits to enable it to operate at those levels (COPE Argument, para. 105-106).

BC Hydro replies to COPE's submissions on Burrard and submits that COPE ignores the fact that Metro Vancouver has the authority to unilaterally amend the requirements of existing air emission permits on the basis of maximum potential operations, and that its powers in this regard under GVRD Air Quality Bylaw No. 1082, 2008 are broad enough to enable it to unilaterally reconsider requirements and amend air emissions permits (BC Hydro Reply, p. 77).

BC Hydro also addresses the technical feasibility issue and points to the numerous caveats and the conclusions in AMEC's Report. The conclusions have led BC Hydro to view that the minimal type of operation necessary, that is, being fully available to operate at all times and to operate at very high load levels during a four-year critical water period to reliably depend on 6,000 GWh/year is unrealistic. Such an operation would force BC Hydro to reduce Burrard's capacity for planning purposes from six reliable units ("N+O, where N=6") to four (600 MW instead of 900 MW). This would negatively impact the more critical Burrard products (reliable capacity and voltage support in the LM), such that the maximum technical capability would be 600 MW and 4,000 GWh/year. It would also cause BC Hydro to start acquiring replacement supply sources in any event to be prepared for major unit failures, "thus making any hoped for additional reliance on Burrard moot" (BC Hydro Reply, pp. 79-81).

Commission Determination

The Commission Panel notes that BC Hydro has taken cognizance of the Commission's directions in its 2006 IEP/LTAP Decision, has retained consultants and has provided a plan that takes into account SD 10, the 2007 Energy Plan, the condition of Burrard, the status of its permits and the uncertainty of 5L83's ISD.

The Commission Panel accepts the evidence that Burrard in its present state cannot with certainty be considered capable of providing capacity or energy over the full planning period. However, the AMEC Report makes it clear that given the necessary expenditures Burrard can be made capable of providing both 900 MW of capacity and up to 6,000 GWh/year of energy over the full planning period.

As to whether BC Hydro intends to incur the necessary expenditures, the Commission Panel notes BC Hydro's testimony that it fully intends to perform the AMEC recommended condition inspections of Burrard's six units, to seek the necessary approvals, commence procurement of major spares and plan the upgrade of the control systems of Units 1, 2 and 3. In the Commission Panel's view this will ensure that Burrard remains as a generating station within BC, capable of providing 900 MW of capacity and up to 6,000 GWh/year of energy and thus fully compliant with SD 10.

For this reason, the Commission Panel endorses BC Hydro's plan to rely on Burrard for planning purposes for 900 MW of capacity. The reliance on energy is considered below.

The Commission Panel has considered the references to Burrard in the 2007 Energy Plan where the government "supports BC Hydro's plan to replace the firm energy supply from Burrard Thermal with other resources by 2014," and agrees with COPE that the plan referenced in the 2007 Energy Plan was not approved by the Commission. The Commission Panel agrees with BC Hydro that the words of the 2007 Energy Plan give it flexibility, and does not consider that BC Hydro's 2008 LTAP is in conflict with the 2007 Energy Plan in respect of Burrard.

The Commission Panel has considered the issue of Burrard's social licence which it views as being a combination of permit compliance and stakeholder engagement management. It is clear that Burrard complies with all its permits (and that the only exceedance at Burrard is caused by an auxiliary boiler which BC Hydro uses to supply steam to the neighbouring refinery) and would continue to be in compliance if operated at the 6,000 GWh/year level, subject only to potential temperature restrictions in its efficient discharge permit.

The Commission Panel views stakeholder engagement management as the role and responsibility of BC Hydro's management to maintain a dialogue with and to inform all of its stakeholders, regulators, government and the public at large of the planned reliance on Burrard, and to fully inform those parties as to not only what the limited operational consequences are of that planning reliance, but also what the material economic consequences of reducing that planning reliance would be. The Commission Panel rejects BC Hydro's argument that by continuing to rely on Burrard at 6,000 GWh/year for planning purposes that it would axiomatically risk losing its "social licence" to operate Burrard.

The Commission Panel has also considered the submissions, particularly from IPPBC, to the effect that differentiating between the planning reliance on Burrard and its anticipated operational utilization could be construed as "circumventing the intent of SD 10" and the Government's climate change related legislation. Given the confusion that was apparent on this point in the proceeding, the Commission Panel inquired of BC Hydro as to whether the "within the Province" aspect of SD 10 was interpreted by it to mandate that electricity delivered to customers in BC had to be generated within BC. BC Hydro's testimony at T6:859 on this matter was clear - no such requirement exists, as was further confirmed at T7:1063.

With respect to the climate change aspect, the Commission Panel notes and accepts BC Hydro's position that it fully understands the requirement of the *Emission Standards Act* that GHG offsets be provided for generation at Burrard for 2016 and beyond.

For all the above reasons, the Commission Panel declines to endorse BC Hydro's proposal to reduce its reliance on Burrard for planning purposes to 3,000 GWh/year for the purposes of this LTAP. Accordingly, the Commission Panel only endorses the part of BC Hydro's request for Endorsement (iii) to rely on Burrard for 900 MW of capacity

For the next LTAP, the Commission Panel suggests that BC Hydro, better informed as it will then be as to the condition of the assets at Burrard and its capital and facility maintenance costs going forward, seriously evaluate the possibility of reducing Burrard's capability for planning purposes to 5,000 GWh/year for the following reasons:

- BC Hydro estimates that during a four year critical water period it would be required to operate Burrard at an average of 5,000 GWh/year. Since the Heritage hydro facilities are planned to operate at an average of 42,600 GWh/year over the same four year critical water period it would appear logical to apply the same standard to Burrard;
- there is a restriction on Burrard's ability to discharge cooling water into Burrard Inlet when the temperature at the end of the cooling water outfall exceeds 27 °C, which limits the quantity of energy Burrard can be relied on to generate in the summer months and which, in the Commission Panel's view, should be reflected in the amount of energy that Burrard can be relied on for planning purposes; and
- the required availability for capacity purposes of 900 MW is seasonal and does not require the same durational reliability as does the capability to generate at the 6,000 GWh/year level; reducing the planning reliance level to 5,000 GWh/year effectively gives rise to a complete on-line spare unit, and should go towards reducing the overall capital costs.

In the alternative, should BC Hydro proceed with a Major Threshold Project ("MTP") or CPCN application in respect of Burrard independently of its next LTAP, the Commission Panel suggests that the Business Case accompanying that application include such a 900 MW, 5,000 GWh/year scenario.

6.5.3 Expenditure of $1.6 Million for Burrard

BC Hydro's Primary Relief 2 (c) requests approval of expenditures of $1.6 million to be spent in F2010 for sustaining capital to ensure the reliability of Burrard as being in the public interest.

Only IPPBC opposes this request, observing that "$1.6 million expenditure is not going to ensure the reliability of Burrard" and that "it is not possible for the BCUC to…approve $1.6 million in sustaining capital expenditures when according to AMEC's estimates, $310 million and perhaps more is required, and BCH's Board of Directors hasn't approved the 'program.'"

IPPBC submits that the Commission should determine that the requested expenditure of $1.6 million under subsection 44.2(3) (a) of the *Act* is not in the public interest (IPPBC Argument, pp. 33 - 39).

BC Hydro replies that it “has to start somewhere to complete the inspections and capital improvements recommended by AMEC” and notes that “denying the actions and associated expenditures won’t make the capacity reliability issue disappear” (BC Hydro Reply, p. 75).

Commission Panel Determination

Given its previous determination in respect of the role of Burrard, the Commission Panel sees no reason to reject BC Hydro’s request for approval of expenditures of $1.6 million in F2010 for sustaining capital to ensure the reliability of Burrard, and accordingly approves the expenditures as being in the public interest.

6.6 Defining and Filling the Gap

Having established its electricity supply obligation, being its Load Forecast less its proposed DSM, and having defined its existing and committed resources, BC Hydro determines its load gap in terms of both energy and capacity and provides its plan to fill those gaps. This Section reviews the gaps that BC Hydro projected and the means by which it planned to fill them.

6.6.1 The Load Gap

6.6.1.1 Energy

BC Hydro calculates the difference between its Load Forecast and its existing and committed resources for selected years in its forecast period to be as follows:

Forecast Load/Resource Gap

GWh	F2012	F2017	F2022	F2027
Reference Load Forecast	61,362	66,172	69,318	73,847
DSM[(1)]	3,000	7,632	10,156	11,616
Electricity Supply Obligation	58,362	58,540	59,162	62,231
Existing and Committed Resources	55,406	55,608	54,786	54,748
Load/Resource Gap	2,956	2,932	4,376	7,483

(Source: Exhibit B-12, BCUC 3.269.1)

BC Hydro proposes to fill this gap as follows:

Proposed resources to address the Load Gap

GWh	F2012	F2017	F2022	F2027
Resource Smart[(2)]	0	0	0	130
Bioenergy Call[(3)]	498	1,126	763	0
2008 CPC[(4)]	0	2,100	2,100	2,100
Future Resources	0	0	1,736	8,211
Non-Firm/Market Allowance[(5)]	2,500	0	0	0
Total	2,998	3,226	4,599	10,441
Surplus	42	294	223	2,958

(Source: Exhibit B-12, BCUC 3.269.1)

Notes:

(1) DSM measures are considered in Section 6.4.

(2) Resource Smart comprises Mica Unit 5. This is not considered further in this Decision.

(3) Bioenergy Call comprises BC Hydro's estimate of the EPAs that will be signed and reach COD as a result of Phases I and II of BC Hydro's Bio-Energy Call. These are not considered further in this Decision.

(4) The 2008 CPC is considered in Section 6.6.2.

(5) Future Resources refers to the energy BC Hydro plans to acquire to meet and exceed its energy supply obligation. It can comprise EPAs, Resource Smart and DSM.

BC Hydro describes the non-firm/market allowance as the amount of energy from non-firm sources external to BC that BC Hydro previously determined it could rely on with a high degree of confidence during periods of low water conditions on the BC Hydro system. Market Allowance was considered in Section 6.2.

6.6.1.2 Capacity

BC Hydro calculates the capacity it will require to meet its load and how it will fill the gap in capacity as follows:

Forecast Demand/Resource Capacity Gap

MW	F2012	F2017	F2022	F2027
Demand Forecast	11,279	11,761	12,398	13,239
Operating Reserves[1]	1,289	1,733	1,733	1,825
	12,568	13,494	14,131	15,064
DSM	531	1,321	1,810	2,120
Total	12,037	12,173	12,321	12,944
Existing and Committed Resources	12,207	12,261	12,197	12,197
Demand/Resource Gap	(170)	(88)	124	747

(Source: Exhibit B-12, BCUC 3.269.1)

Note:

(1) BC Hydro describes its operating reserves as system generating capacity beyond that required to meet peak demand, to ensure sufficient generation is available if some generating units are not available and necessary to meet reliability criteria for planning and operation. BC Hydro states that its reserves are based on 14 percent of total supply excluding the capacity provided by existing and proposed Alcan contracts and the 400 MW market reliance.

BC Hydro proposes to fill this gap as follows:

Proposed Resources to address Capacity Gap

MW	2012	2017	2022	2027
Resource Smart	0	0	0	465
Bioenergy Call	58	113	90	0
2008 CPC	0	163	163	163
Future Resources	0	0	88	372
Total Proposed	58	276	341	1,000
Surplus	228	364	217	253

(Source: Exhibit B-12, BCUC 3.269.1)

6.6.2 Clean Power Call

6.6.2.1 Background

BC Hydro issued a Request for Proposals for "clean" electricity supply from Independent Power Producers ("IPPs") on June 11, 2008. Responses were due on November 25, 2008. In March 2009 BC Hydro announced that it had received proposals as follows:

Results of 2008 CPC

	No. of Proposals	Firm Energy (GWh/yr)	Plant Capacity (MW)	Dependable Capacity (MW)
Hydro Projects	45	8,660	3,870	n/a
Wind Projects	19	8,050	2,790	n/a
Other	4	630	130	n/a
Total	68	17,340	6,790	n/a

(Source: Exhibit B-12, Panel 1.27.1)

BC Hydro makes the following observations concerning the 2008 CPC:

- it was for clean energy only as defined;
- it was designed to elicit proposals from large projects (and with staggered CODs); and
- it was a Request for Proposals ("RFP") which enabled BC Hydro to select a number of proponents and to negotiate mutually satisfactory terms and conditions. BC Hydro contrasts this RFP process with its previous two calls.
  - the 2003 Green Call, which set a price of $55/MWh; and
  - the F2006 CFT, where BC Hydro was obliged to either accept or reject the tenders that were submitted.

(Exhibit B-1, pp 6-28/29)

The original 2008 LTAP states that BC Hydro's intention was to acquire 5,000 GWh/year of firm power before attrition ("gross volume") and 3,500 GWh/year after attrition ("net volume"). Attrition was a subject of some debate in the proceeding, and is discussed in Section 6.6.2.4.

In the Evidentiary Update, BC Hydro amended these volumes to 3,000 GWh/year gross and 2,100 GWh/year net. Shortly thereafter it filed a letter in which it stated that the most recent load forecast in its Evidentiary Update "may not necessarily capture all of the uncertainties inherent in possible future demand for electricity" and "[a]s a result of all of these uncertainties and opportunities, and the 2007 Energy Plan's goal to achieve electricity self-sufficiency by 2016, BC Hydro does not want to limit its opportunities to acquire cost-effective renewable power through competitive processes with independent power producers. This 2008 CPC evaluation process may result in BC Hydro awarding EPAs up to or greater than the original target of 5,000 GWh per year if the EPAs are cost-effective. Such EPAs would be subject to BCUC review under the section 71 filing process" (Exhibit B-11).

6.6.2.2 Requested Endorsement (i)

In its requested Endorsement (i) BC Hydro requests that the Commission endorse its proposed 2008 CPC pre-attrition target of 3,000 GWh per year of firm energy, or alternately its post-attrition target of 2,100 GWh per year of firm energy.

As described in Section 3 of this Decision, BC Hydro seeks "endorsement" by the Commission to provide greater certainty for future filings, and to provide efficiency to the regulatory review process, (Exhibit B-3, BCUC 1.4.1). Further, in the case of the volumes and eligibility, BC Hydro seeks to provide certainty in any ensuing section 71 application it proposes to make following the Commission's decision in the 2008 LTAP. During the Oral Phase of Argument BC Hydro urged the Commission to either endorse the 3,000 GWh/year (gross) or "give us some recommendations on what volume you think would be appropriate" stating that having another LTAP-like debate in the 2008 CPC section 71 filing would be "problematic…and inefficient" (T16:2974-75).

Intervenors' Submissions on the volume which the Commission should endorse range from zero proposed by COPE, to an amount comprising 2,100 GWh/year (net) plus 3,000 GWh/year (net) for "insurance power" proposed by NaiKun. Support for 2,100 GWh/year (net) is provided by JIESC, BCSEA, ESVI, CPC and IPPBC. BCOAPO proposes that the 2008 CPC be deferred to 2011 and, failing that, a target of 1,000 GWh/year be endorsed. CEC submits "that there are much more efficient and effective ways to manage BC Hydro's call process, which will enable BC Hydro to obtain power in a more timely fashion more closely matched to need than the current process provides for" (CEC Argument, p. 145).

BC Hydro discusses reducing the size of the 2008 CPC and the possibility of a two year deferral and notes that any further reduction may preclude some of the large projects it was hoping to attract, although the impact of a two-year deferral would reduce the PV of its BRP portfolio by approximately $60 million, or about ½ of one percent, and would be a benefit to rate payers of that amount. BC Hydro also submits that cancelling the 2008 CPC would have a chilling effect on an industry which the 2007 Energy Plan wishes to see become "vibrant and competitive" (BC Hydro Argument, p. 164).

JIESC observes that the impact on the IPP industry of a termination would be to "detrimentally affect BC Hydro's ability to hold future CFT's and obtain competitive bids" (JIESC Argument, p. 31). BCOAPO disputes BC Hydro's characterization of a deferral as having a "chilling effect" on the IPP industry and points out that BC Hydro has received 68 bids for a total of 17,000 GWh/year from proponents who have invested time and money in preparing proposals and would, in BCOAPO's view, be unlikely to "throw up their hands and walk away" if the call was deferred (BCOAPO Argument, p. 27).

BC Hydro submits that delaying the 2008 CPC creates a risk that adequate IPP supply would not be available in 2-3 years time at competitive and cost-effective price levels, and that many of the larger IPP developers may "exit the BC market in search of more IPP-friendly jurisdictions."

BC Hydro further submits that removing the 2008 CPC and delaying the Bioenergy Phase II Call would mean that the 2008 LTAP would not comply with the self-sufficiency clause of SD 10 (BC Hydro Reply, p. 87)

Commission Determination

In its findings in respect of Burrard, the Commission Panel has rejected BC Hydro's calculations of its existing and committed resources in the 2008 LTAP by declining to endorse the reduction in reliance on Burrard to 3,000 GWh/year. It has also determined that the 2008 LTAP does not adequately address the self-sufficiency requirements of SD 10 and further, that it does not integrate into its supply stack DSM programs and IPP EPAs in ascending cost-effective order.

As a result, the Commission Panel declines to endorse BC Hydro's proposed target from the 2008 CPC of either 3,000 GWh/year gross or 2,100 GWh/year net.

The 68 proposals BC Hydro received from the 2008 CPC can, in the Commission Panel's view, be considered as available resources which BC Hydro can and should manage in such a fashion that the requirements of SD 10 are met in the most cost-effective manner possible.

6.6.2.3 Requested Endorsement (ii)

BC Hydro's requested Endorsement (ii) is that the Commission endorse the clean or renewable eligibility of the 2008 CPC. BC Hydro states that it seeks endorsement of the clean nature of the call to provide certainty in its upcoming section 71 filing of the EPAs from the 2008 CPC. It submits that acquisition of clean, renewable resources helps it meet two of the government's energy objectives set out in section 1 of the *Act*.

BC Hydro states that its portfolio analysis indicated that a clean call portfolio had a weighted average PV of $11.621 million compared to an open call portfolio of $11.647 million (Exhibit B-3, BCUC 1.107.1).

No Intervenor opposed this request for relief.

Commission Determination

The Commission Panel does not find BC Hydro's portfolio analysis to be determinative as the "out-performance" was negligible. That notwithstanding, the Commission Panel endorses the clean or renewable eligibility of the 2008 CPC request for relief, given the government's energy objectives.

6.6.2.4 Attrition

Although the Commission Panel declined to endorse BC Hydro's target volumes from the 2008 CPC on either a pre-attrition or post-attrition basis, it reviews the issues of attrition in this Section and addresses the relief requested by NaiKun.

BC Hydro defines attrition rate as the percentage of EPAs which have been executed by the parties and approved by the Commission and which fail to reach COD for one or more reasons. Its request for relief that the Commission endorse a net target volume envisages a situation where the Commission may endorse a net target and put the onus on BC Hydro to justify its level of attrition based on the specifics of the 2008 CPC when it files its selected EPAs under section 71. In its original application and its Evidentiary Update BC Hydro used an attrition rate of 30 percent. Those Intervenors who take a position fall into several categories: those who accept 30 percent attrition as a reasonable target, COPE which takes no position on attrition, and Columbia Power Corporation, IPPBC and NaiKun who advocate higher levels of attrition.

Notable is NaiKun's submission that, based on BC Hydro's experience in its recent calls, an attrition rate of 67 percent would be appropriate. NaiKun cites the California Energy Commission's report (which BC Hydro had cited to justify 30 percent) which suggests that failure rates of up to 50 percent have been experienced in California calls. NaiKun requests the Commission endorse an attrition rate of 50 percent to 60 percent.

BC Hydro replies that NaiKun based its calculation of BC Hydro's experienced attrition using data on three calls: one of which set a fixed ceiling price for the power to be acquired, the VIPG whose EPA was terminated by BC Hydro rather than by the developer, and the F2006 CFT where two of the larger EPAs accepted by the Commission were cancelled as a result of changes to BC Government policy and legislation setting new standards for coal-fired electricity generating facilities. BC Hydro submits that the refinements in its 2008 CPC such as increased security fees, greater due diligence by BC Hydro, and the opportunity to negotiate certain terms and conditions with the proponents will tend to reduce the level of attrition in the 2008 CPC.

Columbia Power Corporation submits that a call target should not be viewed as an absolute, which might have the unintended effect of preventing cost-effective resource acquisitions (CPC Argument p.5).

IPPBC supports BC Hydro's 3,000 GWh/year pre-attrition target for the 2008 CPC, but does not support and specifically requests that the Commission reject the 2,100 GWh/year post-attrition target, on the grounds that attrition has to be taken into consideration when the Call size is set (IPPBC Argument, pp. 52-53).

Commission Determination

The Commission Panel considers that the historical attrition rate calculated by NaiKun should have little relevance to the 2008 CPC, given the significant differences between it and the three calls relied upon by NaiKun. The Commission Panel reiterates the Commission's Decision at p. 164 of the 2006 IEP/LTAP where it stated that attrition rates of the 2007 call should be "call-specific."

Accordingly, the Commission Panel declines to endorse an attrition rate of 50 to 60 percent as requested by NaiKun.

6.6.2.5 Primary Relief #2(f)

In its Primary Relief #2(f) request, BC Hydro seeks an order pursuant to section 44.2(3) of the *Act* determining that expenditures of $2.0 million in F2009 and F2010 to complete the definition phase work and to implement the 2008 CPC are in the public interest. Only COPE opposes this request and submits that since BC Hydro has not demonstrated any need for the power to be purchased through the 2008 CPC, the expenditure will not be in the public interest (COPE Argument, para. 124).

Commission Determination

At Section 6.6.2 of this Decision, for the reasons given, the Commission Panel has determined that it specifically cannot endorse any volumes of electricity being obtained pursuant to the 2008 CPC. Accordingly, the Commission Panel cannot find that the requested $2.0 million in F2009 and F2010 to complete the definition work and implement the 2008 CPC is in the public interest, and the request is denied.

Elsewhere in this Decision the Commission Panel has provided its guidance to BC Hydro as to how it might remedy the deficiencies in its 2008 LTAP. That notwithstanding, it is clear that BC Hydro has the scope, with or without Commission endorsement, to enter into such EPAs as it contemplated in the 2008 CPC. The Commission Panel finds that the appropriate forums within which the prudency of BC Hydro's decisions, and expenditures in that regard, if any, should be canvassed are, respectively, a section 71 proceeding and a revenue requirements proceeding, pending its next LTAP Application.

6.6.2.6 Relief sought by CEC

In the summary of its argument CEC “recommends that the Commission should direct BC Hydro to introduce negotiation of options to get flexibility from IPP commitments and include those options into the current call process and essentially get a supply side process that has flexibility.”

CEC further pursues the concept of flexibility and “recommends that the Commission find that it is in the ratepayers’ interest that BC Hydro investigate IPP opportunities which create flexibility for BC Hydro in the pursuit of supply side options through contracting with IPPs for “shelf ready opportunities” as opposed to entering into EPAs, the in service date needs for which are doubtful and expensive” (CEC Argument, p. 71).

CEC submits that its proposal would confer a "benefit to the IPP community at this time where there is so much uncertainty about the need for power at all, that a much greater portion of the IPP project proponents would have a potential to recover some of their development costs and keep their prospects for eventually fulfilling a needed power supply role in play at much lower cost that they might otherwise face" (CEC Argument, p. 147).

BC Hydro notes that CEC's assertions of the benefits to the IPP community are not supplemented by any evidence. Addressing the CEC's recommendation, BC Hydro submits that "such IPP options are not a cost-effective or reliable method of acquiring firm energy. IPPs would likely need to be reimbursed for their development costs with no assurance that the option would ever be exercised."

BC Hydro addresses the problems that would need to be resolved to make such an approach practical, such as:

- which projects should be offered an option;
- would it be financeable;
- would the developers be interested;
- how big a pool (of projects) would be required; and
- how would the commercial terms be structured?

(BC Hydro Reply, pp. 87-89)

Commission Determination

The Commission Panel finds that there is insufficient evidence before it on this issue and accordingly denies CEC's request that it direct BC Hydro to introduce options into its IPP commitments.

In Section 6.6.2.2 of this Decision the Commission Panel found that the proposals BC Hydro has received in the 2008 CPC represent a supply of available resources that BC Hydro has the responsibility to manage. That management scope may well include the ability to enter into call option agreements with IPPs.

6.7 Summary Consideration of the 2008 LTAP

The Primary Relief #1 sought by BC Hydro is a Commission Order determining pursuant to subsection 44.1(6)(a) of the *Act* that the 2008 LTAP is in the public interest. BC Hydro submits that the 2008 LTAP meets the requirements of section 44.1 of the *Act* in that it contains the following form requirements:

- an estimate of the demand for energy BC Hydro would expect to serve if BC Hydro does not take new demand-side measures during the period addressed by the plan. BC Hydro filed a 21 year Load Forecast, and in its Evidentiary Update set out the load/resource balance without any 2008 LTAP action items, including implementation of the DSM Plan;
- a plan of how BC Hydro intends to reduce its load/resource gap by taking cost-effective DSM measures and an estimate of the energy that BC Hydro expects to serve after it has taken cost-effective DSM measures. BC Hydro must also include an explanation of why its entire load/resource gap cannot be met with DSM;
- a description of the facilities that BC Hydro intends to construct or extend; and
- information regarding the energy purchases from other persons BC Hydro intends to make, to serve demand after all cost-effective DSM.

In each case, BC Hydro submits it has met the form requirements (BC Hydro Argument, p. 12).

As to whether the Commission should accept or reject the 2008 LTAP in its totality, the Commission received the following specific submissions:

JIESC believes that BC Hydro "has in fact achieved a reasonable degree of overall balance in the 2008 LTAP and deserves the general support of the Commission," but that there are some elements that "need fixing" and the "accept" or "reject" options given to the Commission under the *Act* require that elements of the LTAP be rejected with guidance or suggestions to BC Hydro on the changes that would make them acceptable (JIESC Argument, p. 2).

BCOAPO submits that the Commission “generally accept” the 2008 LTAP (BCOAPO Argument p.29). BCSEA takes the position that notwithstanding its “particular reservation…regarding the DSM Plan,” the 2008 LTAP is in the public interest (BCSEA Argument, para. 4-5).

In addition, BCOAPO submits that according to subsection 44.1 (7) of the *Act* it is possible for the Commission to reject a part of the plan but accept the plan if the Commission Panel finds that “those rejected aspects of the plan are not material” (BCOAPO Argument, p. 3).

CEC submits that the 2008 LTAP does not meet the requirements of section 44.1 of the *Act* (CEC Argument, p. 8).

In its Argument, IPPBC urges the Commission to reject seven parts of BC Hydro’s 2008 LTAP but makes no recommendation as to whether the Commission should accept or reject the 2008 LTAP.

COPE submits that, in accordance with the Commission's jurisdiction under sections 44.1 and 44.2 of the *Act*, the Commission should order that, subject to the four parts that COPE recommends the Commission reject, the 2008 LTAP is in the public interest (COPE Argument, para 136).

The remaining Intervenors take no position on whether the Commission should grant BC Hydro its primary relief.

BC Hydro expresses concern that CEC, as a ratepayer Intervenor, takes the position that the 2008 LTAP does not meet the requirements of section 44.1 of the *Act*, but notes that CEC supports all seven of the expenditure determination requests and the majority of the endorsements for which BC Hydro seeks approval.

Commission Determination

The Commission Panel agrees with the BCOAPO submission that it is possible for the Commission to reject a part of the plan, but to accept the plan if the Commission Panel finds that "those rejected aspects of the plan are not material." Among other things, the Commission Panel has rejected or found deficient the following parts of the 2008 LTAP:

- The Self-Sufficiency obligation established by SD 10 – BC Hydro's proposal did not adequately address this obligation;
- Cost-Effectiveness of DSM Programs – BC Hydro did not demonstrate the cost-effectiveness of its DSM programs against supply-side resources on a marginal basis;
- DSM Plan – BC Hydro allowed its programs to progressively decay over the relevant period; and
- Existing Committed Resources - BC Hydro's proposal to reduce its reliance on Burrard to 3,000 GWh/year for planning purposes was not supported by the evidence.

In addition, the Commission Panel has found these rejected parts have resulted in it being unable to endorse either of BC Hydro's target amounts of firm power from the 2008 CPC.

The Commission Panel believes that the parts of the LTAP it has rejected represent a level of individual and collective materiality that removes the underpinnings of the entire 2008 LTAP. Accordingly the Commission Panel finds that BC Hydro's 2008 LTAP is not in the public interest and rejects it.

In terms of its next LTAP, the Commission Panel requires BC Hydro to present its electricity supply obligations and its plan for acquiring supply-side resources, if any, for a minimum period of 20 years and in accordance with the self-sufficiency criterion of section 3 of SD 10.

In Appendix 2, the Commission provides for illustrative purposes only, its view of a model for summarizing the presentation of the principal parameters of an LTAP.

7.0 OTHER RELIEF SOUGHT IN THE PROCEEDING

7.1 Contingency Resource Plans

BC Hydro's request for Primary Relief #3 is approval of the Contingency Resource Plans ("CRP") for inclusion in BC Hydro's Network Integrated Transmission Services update to BC Transmission Corporation, pursuant to the Commission's Directive 3 of Order G-58-05.

BC Hydro states that CRPs identify alternative sources of supply that could be available should the BRP not materialize as expected, and aim to advance the development of alternative resources to reduce the lead time to being placed in service if the need for the resource arises. If the advanced ISDs are not planned for and maintained, the contingency will be ineffectual.

In developing its CRPs, BC Hydro states that it considered both capacity and energy shortfall risks, but that capacity requirements are its primary concern since capacity is required to meet peak load requirements and maintain system security and reliability (Exhibit B-1, pp. 6-57-58).

The shortfall risks identified by BC Hydro are set out in Table 2-12:

Table 2-12 CRP Shortfall Risks

Risk	Rationale	Capacity Reduction for CRP Purposes (MW)		Energy Shortfall Risk (GWh)	
		F2017	F2028	F2017	F2028
Load Forecast Uncertainty	Peak load and energy requirements can increase as a result of either sustained growth or low temperatures on winter peak.	530	930	3,000	5,200
DSM Deliverability Risk[35]	The DSM Plan as modelled has a significant range of deliverability where the variability is driven by implementation of codes and standards, customer response to rate design and rate increases. The DSM Plan delivers both energy and capacity savings – refer to Tables 6-2 and 6-3 of Exhibit B-1.	270	450	1,400	2,500
Burrard Unit Catastrophic Failure	Given the condition of the units, some units could suffer catastrophic failure, notwithstanding the planned refurbishment work and procurement of critical spares to reduce down time. As a result, one Unit of Burrard was removed for CRP purposes.	150	150	n/a	n/a
Calls Capacity Reduction	Based upon less Bioenergy projects being successful.	50	n/a	400	n/a
Total Reduction:		**1,000**	**1,530**	**4,800**	**7,700**

(Source: Exhibit B-10, p. 35)

BC Hydro states that it would respond to the risks identified and the associated capacity gap increases by advancing the lowest cost capacity resources available to it and that, based upon an expected ISD of 5L83 in October 2014, the least cost resources available to meet load requirements in BC, including the LM/VI region, are the next Mica and Revelstoke units.

Any energy shortfalls that would occur as a result of the BRP supply risks would be managed as follows:

Table 6-19 Energy Contingencies #2

Action	Description
Short lead time acquisition processes	BC Hydro would seek to undertake shorter lead time acquisition processes that could include pre-qualification of bidders and pre-established acquisition rules
DSM Program Adjustment	The DSM programs identified have an ability to adjust the timing and rate of delivery of energy savings.
Market Reliance	In the case of a short term shortfall of energy, BC Hydro would ultimately resort to market energy acquisitions.

(Source: Exhibit B-1, p. 6-60)

BC Hydro states that both CRP's assume the same downside risks but assume different responses, with the main difference being the resources that BC Hydro assumes are required over the plan period. The downside risks are:

Load Forecast	High Load
DSM energy	Option A low range
DSM capacity	Option A adjusted low range
Operational	Reliance on 5 units at Burrard

BC Hydro states that Site C is an option that provides both dependable capacity and firm energy, but since it's development is subject to direction from the BC Government, BC Hydro includes it in CRP #2 to maintain Site C as a feasible option, and to provide the impetus for BCTC to consider the transmission requirements associated with maintaining Site C as a feasible option.

The timing of the two CRPs is as follows:

Unit	BRP	Lead Time	CRP#1	CRP#2
Mica 5	F2025	6 years	F2014	F2014
Mica 6	Not Required	7 years	F2016	F2016
Site C	Not Required	12 years	Not Required	F2019

BC Hydro states that both it and BCTC need to move resources and network upgrades forward to maintain the two CRPs, noting that it is planning to continue to advance Mica Units 5 and 6 as part of its CRP #1, and that following Commission approval, BC Hydro intends to submit it to BCTC such that BCTC ensures adequate transmission is available to deliver the output of these resources to the load centre. BC Hydro expects that as future needs become clearer, the ability to defer or need to construct both the generation and related transmission facilities will become clear (Exhibit B-4, BCUC 2.235.2).

BC Hydro submits that CRPs allow it to take actions on certain resource options by advancing such options through the investigation and definition phases of those projects. This reduces the lead time necessary to implement such options if required to meet some contingency condition that may unfold, and allows BC Hydro to plan to a tighter (smaller surplus) load/resource balance in the mid-term planning horizon than it might otherwise be able to do (BC Hydro Argument, p. 175).

BC Hydro submits that DSM and intermittent resources create significant uncertainty regarding the volumes of capacity that will ultimately be provided, and points out by way of example the 1,700 MW peak reduction (or the equivalent to almost 2,000 MW of supply capacity once the 14 percent reserve is included) DSM is forecast to produce by 2020. This causes the peak demand growth after DSM in the BRP to remain static, with the peak demand in F2023 remaining equal to that in F2009, and results in Mica Unit 5 not being required until 2025. BC Hydro has applied professional judgment in setting out its CRPs, and proposes to advance Mica Unit 5 to F2014 (BC Hydro Argument, p. 179).

CEC agrees with BC Hydro's description of its CRP's and their utility in the planning process and notes the importance of advancing early development stages to shorten lead times in order to gain the values of obtaining these options, as opposed to incurring the full cost of developing them as BC Hydro does in the context of supply options. However, CEC submits that the same logic should apply to DSM and to IPPs and that "the Commission should assess an acceptable long term resource plan as one which has expenditures to be developing DSM contingency options and which has options on IPP projects as contingencies to be implemented if the need occurs."

CEC accepts the resource options BC Hydro is including in its CRPs. However, CEC submits that it would also be appropriate to include DSM options and IPP options (CEC Argument, pp.42-43).

JIESC characterizes BC Hydro's CRPs as "robust resource rich Contingency Resource Plans" (JIESC Argument, p. 16).

Commission Determination

The Commission Panel approves the Contingency Resource Plans for inclusion in BC Hydro's Network Integrated Transmission Services update to BCTC pursuant to the Commission's Directive 3 of Order G-58-05.

7.2 Site C

In its request for Primary Relief #2(e), BC Hydro seeks a determination pursuant to subsection 44.2(3) (a) of the *Act* that expenditures of $41.0 million required to complete Stage 2 Project Definition and Consultation work for Site C in F2009 and F2010 are in the public interest.

Both the 2002 Energy Plan and the 2007 Energy Plan refer to Site C. Policy Action No. 13 of the 2002 Energy Plan states that "While BC Hydro does not plan to invest in the construction of new hydroelectric facilities at the present time, any proposed new BC Hydro hydroelectric facility, such as Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply."

The 2007 Energy Plan states "As part of The BC Energy Plan, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known" (Exhibit A-1-1, Appendix B, p. 26 of 84).

BC Hydro describes its staged process for the evaluation of Site C, whereby it established incremental decision points in a series of stages of project development which are strategically placed to facilitate informed decision-making before the potential next step is taken in the process.

BC Hydro states that each stage, excepting construction, will conclude with its review and analysis of the status of the project followed by recommendations to the BC Government. Following receipt of the recommendations, the BC Government will make a decision as to whether to proceed to the next stage of the process or whether the project should be cancelled or deferred.

The Staged Process currently consists of the following stages:

1) Feasibility (complete and approved);
2) Project Definition and Consultation;
3) Regulatory;
4) Engineering; and
5) Construction.

BC Hydro states that Stage 2 is currently underway and involves further project definition, including environmental, engineering and socio-economic studies, as well as comprehensive consultation with communities, stakeholders, regulators, First Nations, and includes discussion with the Province of Alberta and the Northwest Territories, in order to better understand the benefits, costs, and impacts of the project.

BC Hydro provides a summary of the scope of work in Stage 2:

- engineering work which includes field investigations to confirm slope stability and foundation conditions; flood and earthquake design criteria; availability of construction material; Highway 29 relocation, safeline review, and mapping;
- environmental work including field research such as fish tracking, water quality, and wildlife, and the establishment of Technical Advisory Committees;
- commercial work including preparing a preparing a risk registry, procurement options, and reservoir operating analysis
- third party reviews;

- updated interim project cost estimate;
- First Nations consultation; and
- public, stakeholder and community consultation.

(Exhibit B-1, pp. 6-24 to 6-26)

BC Hydro plans to complete Stage 2 and prepare its recommendations to the BC Government for June 2009.

BC Hydro states that its Potential Large Hydro Project Report (Exhibit B-1-1, Appendix F8) suggests Site C is in the range of cost for other potential large hydro resource options based on a comparative analysis of the ISDs, preliminary cost estimates and relative environmental impacts of those options, which has led BC Hydro to conclude that further investigation of Site C as a potential resource option is warranted (Exhibit B-1, p. 6-23).

BC Hydro provided a comparison between the forecast costs of Stage 2 as set out in the 2006 IEP/LTAP and the amount for which it requests approval in the 2008 LTAP and ascribes the increase of $20 million in the cost estimate as being caused by:

- lengthening the timeline from 10 months to two years to allow for an expanded engagement with First Nations and communities;
- additional project definition work involving a large number of technical, engineering, environmental and socio-economic studies that are planned or underway for Stage 2, including work that was originally planned for stages other than Stage 2, as well as additional work not included in the scope for the 2006 IEP/LTAP estimate;
- a change in BC Hydro's policy to start allocating interest during construction and overhead costs directly to projects including Site C.

(Exhibit B-3, BCUC 1.126.1)

PVEA is the only Intervenor to oppose BC Hydro's request. PVEA submits that the Commission should reject the inclusion of Site C as part of the 2008 LTAP, and disallow the $41 million Stage 2 costs of Site C. PVEA submits that, if the Commission determines that the 2007 Energy Plan did not require these expenditures, the onus falls on BC Hydro to establish their prudence and reasonableness. In PVEA's submission, given the limited role Site C plays in the 2008 LTAP and the very limited role it plays in meeting the self-sufficiency goals of SD 10, these expenditures are not reasonably incurred at this time, and should be rejected (PVEA Argument, p. 11).

PVEA further comments as to its view of the inadequacies of BC Hydro’s stakeholder engagement processes in the affected area (PVEA Argument, p. 7).

JIESC supports the $41 million requested in the Application to complete Stage 2 of the Site C project, but expresses concern that “high level expenditures not continue on indefinitely without a higher level of commitment to proceeding to construction”(JIESC Argument, p.36).

CEC supports the expenditure of $41 million for the project definition and consultation with respect to Site C as being in the public interest (CEC Argument, p.41).

In Reply BC Hydro submits that PVEA inaccurately portrays BC Hydro’s position and points to its President’s testimony that it would be imprudent for it not to consider Site C as a potential option in the 2008 LTAP (BC Hydro Reply, p. 92).

Commission Determination

The Commission Panel accepts BC Hydro’s position that it is proceeding in accordance with the stated action plans and objectives of the 2007 Energy Plan, and accepts that Site C is a suitable resource option to be considered in BC Hydro’s long-term planning process. The Commission Panel finds that the expenditures of $41 million on Stage 2 are in the public interest.

7.3 Capital Plan Review Process

In Endorsement (viii), BC Hydro requests Commission endorsement of the current capital plan review process which BC Hydro filed as part of its F2009/F2010 Revenue Requirements Application (“F09/10 RRA”). BC Hydro states its approach arose from the F07/F08 RRA Negotiated Settlement

Agreement ("NSA") and provides the Commission and Intervenors with sufficient details of BC Hydro's planned capital expenditures, while meeting BC Hydro's objectives of:

- satisfying the requirements of the *Act* while maintaining flexibility to address unique situations;
- presenting the scope and magnitude of all its capital plans in one place;
- providing a single point of reference for its capital projects; and
- minimizing the regulatory burden.

BC Hydro notes that the while the RRA proceeding is the appropriate venue for the filing, as many of its capital expenditures are unrelated to the identification and acquisition of resources for the purposes of the LTAP, the LTAP Proceeding may be its preferred venue for what it deems to be "growth related [Major Threshold Projects]" ("MTPs").

BC Hydro submits that while section 44.2 of the *Act* addresses the filings, and review of expenditure schedules by public utilities for, among other things, capital expenditures, that in respect of capital expenditures, the section is "permissive" i.e., "A public utility may file…" Notwithstanding the permissive nature of subsection 44.2(1), BC Hydro states that it is appropriate for it to file applications for major capital projects under subsection 44.2 (1)(b) of the *Act,* that for projects in excess of $50.0 million (the MTPs) it will seek a public interest determination under subsection 44.2(3)(a) of the *Act*, and that all its MTP applications will be consistent with the Commission's CPCN guidelines.

BC Hydro further states that, with the exception of DSM, it will bring forward all capital projects where it plans to seek, or has obtained, the approval of its Board of Directors for an expenditure of $50 million or more regardless of the functional area of the project. Subject to urgency of need and other scheduling considerations, BC Hydro will file all such projects as either part of its LTAP applications (for growth related generation MTPs), or its RRA applications, or as individual applications.

Lastly, BC Hydro anticipates that "it may seek, or the Commission would require, on an exception basis, section 44.2 determinations in respect of projects or programs that do not meet the threshold test" (BC Hydro Argument, pp. 77-79).

Pursuant to Issue Number 7 of Exhibit A-21, the Commission Panel invited submissions as to whether BC Hydro's threshold definition for its MTPs should include those situations where a number of projects might constitute a "program" which in total would exceed the threshold of $50-million or more, but the elements of that program would not individually exceed the threshold.

BC Hydro acknowledges that its capital planning can also include a "program" rather than a discrete project, and that such programs are usually defined in the context of a broader series of replacement or refurbishments of a number of similar pieces of equipment or assets, generally found in several locations, and that such programs will often continue for a number of years. BC Hydro does not propose to apply its threshold test to the entire cost of such programs, only the individual projects within such a program.

BC Hydro submits that its approach does not preclude an Intervenor or the Commission from acquiring information about projects that are expected to cost less than $50-million or that are linked to or drive other expenditures. BC Hydro notes that its capital plan filing has the necessary degree of transparency to enable such inquiries in that all projects and programs are itemized if they will cost more than $2.0-million (BC Hydro Argument, pp. 79-80).

JIESC, while accepting $50 million as an appropriate threshold for a MTP or CPCN review except for building and Information Technology ("IT") projects, submitted that those proposed exceptions should be subject to a $10 million threshold, noting that "scope and cost estimates for IT projects have expanded considerably in the past after projects have been commenced without commensurate consideration or measurement of benefits and accordingly deserve early and ongoing examination."

JIESC also registered its concern that capital programs not be broken into a number of individual projects to review, and is of the view that “a program that consists of a number of capital projects with total costs of over $50 million (within a three year period) should be subject to a major project or a CPCN review (JIESC Argument, p. 10).

CEC generally agrees with BC Hydro’s approach but “recommends to the Commission that when a program in aggregate meets the threshold, it should be included [as a MTP]” (CEC Argument, p. 18).

While not objecting to BC Hydro’s proposal to file capital plans bi-annually as part of its future RRAs, IPPBC does not agree with BC Hydro’s proposal to submit its MTPs to the Commission for approval under subsection 44.2(1) (b) of the *Act* and submits that section 45 is the appropriate section i.e. an application for a CPCN. It points to the limited ability of the Commission to exercise discretion under subsection 44.2(1)(b) of the *Act*, in that it can only accept or reject a schedule or part of it and cannot make selective improvements or modifications to the project. Further, IPPBC does not agree with BC Hydro’s proposal to bring forward MTPs where BC Hydro is still seeking approval of its own board, stating that “IPPBC does not want to commit scarce resources to examine projects that BC H[ydro]’s Board of Directors hasn’t even approved.” Accordingly IPPBC “specifically and respectfully submits that BCUC should reject BC H[ydro]’s proposals with respect to submission of [MTPs] in accordance with subsection 44.2(1) (b) of the [*Act*]” (IPPBC Argument, p. 49).

Other Intervenors (BCOAPO, BCSEA) either generally supported or did not comment on BC Hydro’s proposals.

In reply, BC Hydro does not specifically address either of CEC’s or JIESC’s proposals for treating programs which aggregate to over $50 million as MTPs. BC Hydro does, however, state that “there is no evidentiary basis” for JIESC’s assertions in respect of its request for a $10 million threshold for IT projects, and that that request ought to be dismissed by the Commission.

With respect to IPPBC's position that the Commission should require BC Hydro to apply for CPCNs pursuant to subsection 45(5) of the *Act* for all such MTPs, BC Hydro submits that "if the Commission were to impose such a requirement it would be committing an error in law because it would be fettering its discretion" (BC Hydro Reply, p. 10).

BC Hydro's extensive submissions on this matter in its Final Argument arose from a request by Commission Counsel that BC Hydro address in its Argument whether "there is any reason that the Commission should not, under subsection 45(5), direct that all applications for [MTPs] must be filed under sections 45 and 46" (T5:766). The principal thrust of BC Hydro's argument is that "the adoption of such a policy would be an error of law, because it would amount to a fettering of the Commission's discretion" (BC Hydro Argument, p.81).

BC Hydro acknowledges that while a statutory delegate of authority is afforded some latitude in making general policy or general guidelines that assist in the efficient administration of that authority, it submits that "[a] problem will arise upon the blind application of a policy by the decision-maker without consideration of the facts of the specific circumstances before it," and cites *Re Maple Lodge Farms Ltd. and Government of Canada et al* as authority for that position.

Given the discretion that both the public utility, in applying for, and the Commission, in requiring or granting, a CPCN application in terms of both the circumstances and the value of the proposed project, have under *s.* 45 of the *Act,* BC Hydro submits that such an "inflexible policy" as contemplated by the Commission Counsel's question (and by IPPBC's request) would amount to a "predetermination of the matter...regardless of the circumstances," and as such would fetter the discretion of the Commission (BC Hydro Argument, pp. 82-83).

Commission Determination

In terms of BC Hydro's request for an endorsement of its overall approach to filing and review of its capital plans, the Commission Panel notes the seemingly dichotomous approach taken by BC Hydro to the same subject in the recent review of its F09/F10 RRA. In that proceeding BC Hydro filed a voluminous list of present and contemplated capital projects and programs, at various stages of development and, in many cases, with a wide range of project cost estimates, while submitting that its filing was by way of "compliance" with the outcome of its F07/F08 RRA NSA and that it otherwise sought no relief in [that] proceeding with respect to its capital plan (*In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements*, Decision dated March 13, 2009 ("F09/F10 RRA Decision," p. 199).

In that proceeding, the Commission had invited submissions from the parties as to how, and in what forum, might BC Hydro's capital plans be reviewed. BC Hydro submitted since it had no plans to proceed with any new, unapproved capital projects with a cost exceeding $50 million, that the issue concerning future capital plan reviews could be addressed in the 2008 LTAP proceeding (ibid pp. 199-201).

Also in that RRA proceeding, there was a diversity of views among Intervenors as to an effective approach to the filing and reviewing of BC Hydro's capital plans. Such consensus as arose was to the need for there to be an effective process given the material impacts of BC Hydro's capital spending on its Revenue Requirements. As well, there was a general consensus that the matter should be more thoroughly canvassed in the course of the review of the 2008 LTAP.

In the F09/F10 RRA Decision, the Commission noted that "the capital review process pursuant to the *Act* contemplates that those matters will be addressed in the context of an LTAP proceeding" and accordingly recommended BC Hydro to "include in its next RRA the revenue requirement implications arising from planned capital expenditures during the test period, and also ask[ed] that those implications be clearly set out for each such capital item" (ibid p. 202).

The Commission Panel's concern with the approach BC Hydro has asked the Commission to endorse in this proceeding is that it provides insufficient regulatory certainty to the Commission and the Intervenors as to the type of projects that will be brought forward for approval in what time frame and in what venue. The Commission Panel contrasts BC Hydro's approach with that of other public utilities under the Commission's jurisdiction, where capital plans are filed on a regular basis, and projects, including programs comprised of linked projects which exceed an agreed upon threshold value, are brought forward for approval by way of a CPCN application complete with an analysis of alternatives and accompanying business case. **Accordingly, the Commission Panel declines to endorse BC Hydro's approach to filing its Capital Plans, on the basis that it contributes little if anything to improved regulatory efficiency.**

Before providing its guidance to BC Hydro as to the elements of an approach the Commission Panel would be prepared to endorse the Commission Panel will address the specific requests for relief brought by Intervenors in the matter of BC Hydro's capital plans as follows:

- **JIESC's request for an MTP threshold of $10 million for IT and building projects is rejected by the Commission Panel as JIESC has provided no evidentiary basis for it.** As BC Hydro has demonstrated, all Intervenors, and the Commission have access to its proposed capital projects of over $2.0 million, and have the opportunity to initiate a request for review of any of them, at which time such evidence, if any, can be tabled;
- **JIESC's request, concurred with in principle by CEC, that programs consisting of individual projects, as defined by BC Hydro, which are linked in functional and/or geographic terms and in which the aggregate of the individual projects achieves the MTP threshold of $50 million within a three year spending period constitute a MTP and be subject to a MTP review, is acceptable to the Commission Panel as being consistent with the practice of other public utilities under the Commission's jurisdiction.** In this regard, the Commission Panel notes and by way of example refers to the 2008 CPCN Application by Fortis BC in respect of its Copper Conductor Replacement Project. (Order G-165-08 dated November 7, 2008);
- **IPPBC's request that all BC Hydro's MTP review applications be by way of a CPCN Application under section 45 of the *Act* is rejected by the Commission Panel, as IPPBC has provided no alternative authorities to refute that which supports BC Hydro's view that such a policy would in fact be tantamount to the Commission fettering its discretion.** The Commission Panel notes that IPPBC was in fact informed of BC Hydro's argument and support for its view at the time IPPBC submitted its request for relief; and
- **IPPBC's request that BC Hydro not bring forward for review MTPs that have not been formally approved by its Board of Directors is accepted by the Commission Panel as being in accordance with proper corporate governance principles and practices.** In the event of unusual circumstances, BC Hydro should take the necessary steps to secure an "Approval in Principle" resolution from its Board of Directors if time or insufficiency of information constraints preclude that formal approval having been obtained before filing its MTP, and explain those circumstances in its Application.

In order to provide an overall framework for an approach it is prepared to endorse, the Commission Panel would recommend the filing of BC Hydro's long term capital expenditure plans in the context of its LTAP applications, rather than in the context of an RRA or as a separate regulatory process. Principal among the Commission Panel's reasons is the reality that, in the aggregate, all of BC Hydro's planned capital expenditures are directed towards the statutory obligation to satisfy its customers' requirements for reliable electricity service.

The LTAP review is focused on quantifying what those requirements are over a twenty year planning period, and whether they should be satisfied from (i) existing assets for which the continuation of supply requires capital expenditures, (ii) DSM, or (iii) new supply. While no such particular circumstances arose in the course of the present review, the Commission Panel can foresee circumstances where it may well be more cost-effective for BC Hydro to plan to enhance its DSM programs, or to plan for new supply, than to plan for the continuation of service at design capability levels from the entirety of its existing heritage asset base, much of which, as BC Hydro testified to in the F2009/F2010 RRA proceeding, is aged and in a poor state of repair. The Commission Panel believes that an LTAP proceeding, rather than an RRA proceeding, is the appropriate forum for such matters to be considered. As the Commission found in the F09/F10 RRA Decision, the important issue for consideration in an RRA review is the impact of the implementation of BC Hydro's capital plan over the test period under review, rather than the plan itself.

In its capital plan submission for the next LTAP proceeding, the Commission Panel suggests that BC Hydro clearly identify, in each category of planned expenditure, those projects or programs (as the Commission Panel has noted above), that meet, or are expected to meet its MTP criteria, the forum in which it expects to file the MTP for review by the Commission and Intervenors, and the likely timing of such filing.

For MTPs that for good reason do not relate logically to, or otherwise cannot be efficiently dealt with in the course of, an LTAP proceeding, the Commission Panel accepts BC Hydro's position that they can be filed either in the course of an RRA proceeding or as separate applications. For regulatory consistency and effectiveness, the Commission Panel strongly suggests that BC Hydro file them as CPCN Applications under section 45(5) of the *Act.*

For those MTPs that do logically fall within the context of an LTAP review proceeding, the Commission Panel accepts BC Hydro's position that the *Act* contemplates that they may be filed under section 44.2 and BC Hydro's commitment that they will be filed in a "CPCN – like" manner. Having said that, the Commission Panel notes BC Hydro's submissions in the course of its response to item 7 of the agenda for the Oral Phase of Argument that while "BC Hydro accepts that the Commission may set conditions on its acceptance of the $140.1 million expenditure schedule for…FNU3 under Subsection 44.2(3)(a) of [the *Act*]," it goes on to state: "In particular, BC Hydro notes that the Commission has the power to impose <u>reporting requirements</u> pursuant to other sections of [the *Act*] such as section 43, which is the duty to provide information" (T16:2994-95, emphasis added).

In its oral submissions, IPPBC asked the Commission Panel to consider imposing "…conditions that put some personal responsibility on some of the people advancing the projects. In other words that their performance bonuses be tied to the performance cost estimates for the projects" (T16:2997). In reply, counsel for BC Hydro submitted that "…if we're getting into risk/reward systems or cost collars, I would have lengthy submissions on the <u>jurisdiction of the Commission or lack thereof, I might underline"</u> (T16:2999, emphasis added).

The Commission Panel notes that while conditions such as cost collars on the Fort Nelson Generating Station Upgrade Project were not an issue in the proceeding, it is not uncommon for them to be found to be in the public interest in the Commission's approvals of CPCN applications it has reviewed for other public utilities, as such conditions are within the Commission's discretion under section 45 of the *Act*. If the Commission Panel were to determine, in advance, that it endorsed BC Hydro's plan to file MTPs under section 44.2 of the *Act* it might be seen as equally fettering its discretion as if it had determined in advance that all BC Hydro's MTPs had to be filed as CPCN applications.

Should BC Hydro elect to file an MTP application under section 44.2, given the Commission's more limited jurisdiction under that section than under section 45 were it to find that that MTP could only be approved as being in the public interest with conditions other than simply "reporting," it would have no alternative but to reject the application for future resubmission, if any, by BC Hydro, with corollary delays and regulatory inefficiency. The Commission Panel suggests that BC Hydro consider filing those MTP applications that relate to an LTAP proceeding contemporaneously as CPCN applications in order to preclude those undesirable possibilities, while filing its capital plan per se under section 44.2. In that manner, "duplicate" or "fall-back" applications such as BC Hydro provided in this proceeding, with Fort Nelson Generating Station Upgrade Project Case 2 as an alternative to Case 3.2, would not be necessary.

For all the above reasons, and given the flexibility provided by the *Act* to both public utilities and the Commission, the Commission Panel declines to provide BC Hydro with prescriptive guidance as to how it should file its capital plans for review, other than that they should be filed as part of an LTAP proceeding. As to the form of, and proceeding in which it files its MTP applications, the Commission Panel requests that, at its earliest convenience but in any event no later than 6 months from the date of this Decision, BC Hydro file with the Commission a set of guidelines within which it is prepared to make MTP filings and applications and that that set of guidelines reflect such consultations with its Intervenors and Commission staff as BC Hydro deems appropriate.

7.4 Timing of Next LTAP Application

BC Hydro re-affirms its request for a "minor adjustment" from its bi-annual LTAP filing schedule as accepted by the Commission in its review of BC Hydro's 2006 IEP/LTAP application to a flexible schedule by which its subsequent filings "would generally be approximately two years [from] the date of the Commission's decision on the previous LTAP." BC Hydro submits that the benefits of this approach would include more time for consideration of the Decision, to undertake additional analysis, to consider rapidly evolving government policy, and for proper stakeholder engagement, and would outweigh the only drawback – that there would be uncertainty as to the filing date. BC

Hydro notes that, given certain assumptions as to the length of the review process, the period between LTAPs would be some 2.5 to 3 years (BC Hydro Argument, pp. 95-96).

Many Intervenors took no position with respect to BC Hydro's proposed schedule. BCSEA and JIESC supported in principle the concept of the Decision date in the prior LTAP triggering the filing of the next, but differed as to the period to be provided to BC Hydro for its consideration and preparation. BCSEA proposed a fixed 3 year period from the prior Decision; JIESC proposed a 24 month fixed period, with a further 2 month "contingency period" to a maximum of 26 months from the prior Decision (BC Hydro Argument, p. 32).

Terasen, CEC, and IPPBC all requested that the Commission reject BC Hydro's proposal, albeit for different reasons.

Terasen proposed that "[m]aintaining the present two-year regulatory cycle for BC Hydro's LTAP will help ensure that pursuit of Electric Load Avoidance DSM does not languish while new, higher cost, supply initiatives (e.g. the Clean Call) proceed" (Terasen Argument, p. 3). Terasen's "Electric Load Avoidance" DSM initiative contemplates the encouragement of high-efficiency natural gas appliances for heating in lieu of electric appliances for such applications, and is dealt with in Section 7.7.7 of this Decision.

CEC submits that BC Hydro's proposal is not a "minor" adjustment to the LTAP filing cycle, and cites as reasons for rejecting it "that there are a number of significant moving targets in energy policy, the economy, and the Province's views on climate change that BC Hydro needs to be constantly monitoring and improving its information with respect to what the impact of these changes are on its long term planning." While acknowledging that LTAP proceedings require significant resources, CEC argues that "the investment in regulatory process which mitigates (sic) against high cost initiatives which are locked in for the long haul justify this higher level of regulatory scrutiny at this time" (CEC Argument, p. 17).

IPPBC requests that BC Hydro's proposal be rejected, as it "… will result in a 3 year review cycle at a time when the demand is likely to significantly increase as a result of fuel switching [to electricity] caused by GHG related legislation and policies" (IPPBC Argument, p. 50).

BC Hydro "agrees with and adopts the words of the JIESC as to why a two year, as opposed to a one year, assessment period [before the next LTAP filing] is the appropriate interval", i.e. "….two years as an adequate interval to reflect meaningful change, gain increased insight into future trends, and allow BC Hydro to understand and respond to the most recent Commission LTAP Decision and Provincial policy changes."

With respect to the positions taken by those Intervenors with contrary views, BC Hydro firstly replies that "Terasen's position is not supported by any other Intervenor, and is completely rejected by BC Hydro."

With respect to CEC's position, BC Hydro replies only to an un-referenced request on CEC's part as to "the need to identify additional cost-effective DSM," by a filing date of June 2010. BC Hydro submits that "no materially new data on the DSM programs will be available in time to be incorporated in a new LTAP if there were a June 2010 filing date."

BC Hydro makes no reply to IPPBC's position (BC Hydro Reply, p. 34).

Commission Determination

Elsewhere in this Decision the Commission Panel has determined that there are several areas of concern and deficiency within BC Hydro's 2008 LTAP filing. It has provided extensive guidance to BC Hydro as to how those might best be dealt with. Rather than suggesting that BC Hydro re-file the 2008 LTAP in whole or deal with those deficient parts prior to its next filing the Commission Panel finds that the most efficient course of action would be for BC Hydro to take those matters into account in its next LTAP filing, except where specifically directed to do otherwise in this Decision.

The Commission Panel also notes the parties' general concurrence as to the dynamic and uncertain nature of the present economic and policy environment, and its implications on BC Hydro's planning, and further the long-term materiality of the impacts to ratepayers arising from BC Hydro implementing its plans. **Accordingly the Commission Panel determines that BC Hydro's next LTAP filing should be on or before June 30, 2010.**

Having made that determination, the Commission Panel does not find it necessary to deal with BC Hydro's request for an amendment to its LTAP filing schedule at this time. Should BC Hydro wish to pursue that initiative in the future, it may do so.

In the absence of any comment from Intervenors, the Commission Panel has no objection to BC Hydro's proposed change of nomenclature for its future long-term resource plans from IEP/LTAP to LTAP.

7.5 DSM Plan Expenditure Request

In its request for Primary Relief #2(a) BC Hydro seeks a Commission determination that expenditures of $418.0 million in F2009, 2010, and 2011 for implementation of the DSM Plan are in the public interest. As previously described, this amount has not been adjusted as a result of the Evidentiary Update, notwithstanding that projected savings from DSM initiatives were reduced. BC Hydro justifies this position because changed economic circumstances could increase the difficulty of achieving its targeted savings; it can reduce the level of expenditures in future years if additional DSM savings are not needed; and, the DSM cost is still relatively low when compared to supply options (BC Hydro Argument, p. 124).

BCOAPO tacitly supports this expenditure with its support of Adjusted Option A (BCOAPO Argument, p. 14).

CEC recommends approval of a further $46 million of additional expenditures for DSM initiatives beyond adjusted Option A to enable BC Hydro to advance planning, preparation, and where possible, launch for additional DSM initiatives (CEC Argument, p. 6). BC Hydro submits that CEC has not provided evidentiary support for this and that the Commission lacks the jurisdiction to compel it to incur an additional $46 million on DSM (BC Hydro Reply, p. 61).

Commission Determination

The Commission Panel has rejected BC Hydro's Adjusted Option A DSM Plan because it has not demonstrated that it represents adequate cost-effective DSM. Nevertheless, the Commission Panel considers that for the purpose of a subsection 44.2(8)(c) determination it can consider the cost effectiveness of the DSM on a portfolio basis by reason of the operation of subsection 4(1)(c) of the M271.

The Commission Panel finds that the expenditure schedule of $418.0 million to implement DSM Plans generally as described in BC Hydro's Adjusted Option A in F2009, F2010, and F2011 is in the public interest pursuant to subsection 44.2(3) of the *Act* and is accordingly approved.

The Commission Panel finds that there is no evidence before it on which to base an instruction to BC Hydro to increase Option A expenditures by $46.0 million as requested by CEC. The Commission Panel denies CEC's request for that relief.

7.6 Capacity-Related DSM Expenditure Request

In its Primary Relief #2(b) BC Hydro requests that the Commission determine that expenditures of $600,000 in F2009 and F2010 to undertake and complete the definition phase work for capacity-related DSM are in the public interest.

BCOAPO, BCSEA, and CEC generally support BC Hydro's position.

JIESC comments on the Smart Meter Initiative ("SMI") and the way that the SMI relates to this aspect of the 2008 LTAP. JIESC expresses concern at the contrast between the potential estimated expenditure on smart meters and the limited DSM savings to be achieved at a time when rate-payers are facing substantial repetitive increases at rates two to three times the rate of inflation. In JIESC's view such high expenditures cannot be justified. The SMI initiative projects savings of approximately 320 GWh/year by F2028, which JIESC describes as "simply inadequate for a program that will cost in the range of $730 million to $930 million." JIESC submits that it recognizes that the Commission's options with respect to the SMI programs are limited but urges the Commission to have BC Hydro file a business case, and if that business case is not persuasive, to direct BC Hydro to review the wisdom of proceeding with SMI with its Shareholder, in much the same way the Commission requested BC Hydro to discuss the cap on Trade Revenue with the Shareholder in its recent RRA Decision (JIESC Argument, p. 26-27).

Subsection 64.04(3) of the *Act* requires BC Hydro to install smart meters by the end of 2012, and BC Hydro's DSM Plan assumes it is in conformance with the *Act*. BC Hydro states that SMI itself will not result in energy conservation and does not include SMI costs in the DSM Plan. However, selected DSM activities will leverage the capabilities of SMI in conserving energy. The cost of these DSM activities and their associated electricity savings are included in the DSM Plan. Time-of-use and critical-peak rate structures, which would be enabled by SMI, are not included in this energy-focused DSM Plan. They are, however, included in the scope of proposed definition phase work on capacity-focused DSM.

BC Hydro states that the DSM Plan includes 78 GWh of energy savings for the period F09 to F11 that are enabled by SMI. Additional DSM energy savings of 320 GWh/year by F2028 that are enabled by SMI are also included in the DSM Plan.

Additional energy savings from SMI may also result from diversion detection as well as enhancement of existing Volt Var Optimization ("VVO") initiatives. However at this time, such savings are not known, due to, among other things, the fact that the government has yet to issue regulations concerning the SMI, the enabling technology has consequently not been selected, and the required comprehensive field testing of same in BC Hydro's service area has not yet occurred. The SMI regulation will be a determinant of the scope of SMI (Exhibit B-1-1, Appendix K p.94; Exhibit B-4-3, JIESC 2.23.3).

Commission Determination

Having regard to the statutory requirements on BC Hydro, the Commission Panel finds that it is premature for it to make determinations in respect of smart meters before any regulations have been issued and before BC Hydro's business case has been examined. Accordingly it makes no finding or direction with respect to the relief sought by JIESC, other than to acknowledge the reasonableness of its suggestion that BC Hydro engage in further policy discussions with the government as appropriate.

The Commission Panel determines that expenditures of $600,000 in F2009 and F2010 for definition work for capacity-related DSM are in the public interest and approves BC Hydro's Primary Relief #2 (b).

7.7 DSM General

7.7.1 Filing of DSM Performance Reports

In Endorsement (v), BC Hydro requests that the Commission endorse the filing of DSM performance reports on an annual basis. BCOAPO and BCSEA support this (BCOAPO Argument, p. 18; BCSEA Argument, p. 35), while JIESC proposes quarterly reporting of DSM (JIESC Argument, p. 27).

IPPBC submits that it has reviewed selected evaluation reports, and is of the view that such reports are inadequate to allow the Commission to make informed judgments about the true cost-effectiveness of any of the specific programs (IPPBC Argument, p. 23).

BC Hydro submits that JIESC has offered no specific evidence as to the value that would be gained from increasing its reporting frequency. BC Hydro submits that reporting on an annual basis aligns with subsection 43(1) (ii) of the Act, MEMPR's intent for annual reporting, and as well, the Commission's recent Decision which addressed the frequency of Terasen Utilities' DSM reporting (BC Hydro Reply, p. 67).

Commission Determination

The Commission Panel endorses the filing of DSM performance reports on an annual basis going forward. BC Hydro is directed to file its report for the year ended March 31, 2009 with the Commission on or before September 30, 2009. In succeeding years it should endeavour to file its annual report on a timelier basis with June 30 of each year as a target. As a transition measure, BC Hydro is directed to file its last semi-annual report, for the period ending September 30, 2009, by no later than March 31, 2010.

7.7.2 JIESC's Requests for DSM-Related Relief

7.7.2.1 DSM Program Monitoring

JIESC points to its cross-examination of BC Hydro's witness panel on the subject of milestones and mitigants, and submits that "the result was a clear demonstration that there are no program specific milestones, much less mitigation measures" (JIESC Argument, p. 27).

JIESC submits that "what BC Hydro is proposing to do with respect to milestones is to first implement the programs, see what results it obtains, then set the milestones and if they all don't add up to enough to meet the forecast total for all DSM program, consider mitigation. BC Hydro's DSM plan is an aggressive and costly $400 million plus program that must meet customer needs but does not have milestones or mitigation plans." JIESC submits that "this amounts to an unacceptable failure to manage" (JIESC Argument, pp. 29-30).

JIESC urges the Commission to reject the DSM plan as presented and direct BC Hydro to re-file it within two months in a format that sets out “reasonable annual program specific milestones and proposed mitigation measures, including shifting program resources and alternative supply options for each program” (JIESC Argument, p. 30).

BC Hydro states that it has identified a number of indicators that it proposes to use to manage and mitigate DSM deliverability risks, but does not provide specific details about metrics, milestones, or mitigants in its Application (Exhibit B-1, pp. 6-8, 6-9).

BC Hydro commits to “closely monitor the performance of DSM activities by tracking energy and capacity savings, as well as develop and maintain a number of milestones and indicators to anticipate shortfalls and trends that may trigger the need for adjustments to the DSM Plan” (BC Hydro Argument, p. 124).

Commission Determination

The Commission Panel has already made its determinations under section 44.1 of the *Act* in respect of the DSM plan in Section 6.4 of this Decision and JIESC’s request for relief is accordingly denied.

That notwithstanding, with respect to the content of BC Hydro’s DSM reports, the Commission Panel finds that, given the statutory profile of DSM, and the material consequences to ratepayers of the results of BC Hydro’s initiatives, these reports should include metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective.

7.7.2.2 Industrial Programs

JIESC argues that BC Hydro is not pursuing all cost effective DSM programs, specifically because of insufficient attractive industrial DSM programs "in spite of 50% of targeted DSM programs savings are to come from the industrial sector" (JIESC Argument, p. 23). It submits that "BC Hydro needs industrial DSM if it is going to meet its DSM program goals" (JIESC Argument, p. 25).

JIESC urges the Commission to direct BC Hydro to immediately make available reasonable industrial DSM incentives up to the cost of IPP purchases. JIESC also recommends the Commission direct BC Hydro to hold a Call for Tenders for Industrial DSM, and submits that the results of such call "would clearly demonstrate the amount of cost effective DSM available in the industrial sector and provide a good comparison between DSM incentives and supply side measures" (JIESC Argument, p. 25).

BC Hydro allows that the take-up of incentives directed at its transmission customers has been slow and indicates that it is reviewing the industrial DSM programs to assess whether adjustments need to be made.

BC Hydro submits that it would be inappropriate for the Commission to require it to increase and fix the incentive levels for industrial DSM and submits that JIESC's suggestion that incentive levels should be increased to the cost of IPP purchases would require BC Hydro to over-pay for industrial DSM savings which would be both imprudent and unfair to BC Hydro's other ratepayer classes.

BC Hydro states that it is reconsidering its strategy for industrial DSM based on feedback from its customers, but notes that there is no evidence to suggest that a Call for Tenders would result in increased electricity savings or lower costs. BC Hydro submits that such a Commission directive would be unfounded at this time (BC Hydro Reply, pp. 69-70).

Commission Determination

The Commission Panel considers that industrial DSM programs are a subset of BC Hydro's more pressing problem namely how to successfully execute its DSM plan. Given that BC Hydro has no milestones in place yet it would be premature for the Commission to prejudge the success or failure of the industrial DSM programs and require BC Hydro to adjust its incentives or to conduct a CFT for industrial DSM, as requested by JIESC.

Accordingly, the Commission Panel declines to grant JIESC's request to direct BC Hydro to enhance its industrial DSM incentives and to hold a Call for Tenders for Industrial DSM.

7.7.2.3 Termination of Cost-Ineffective Programs

JIESC submits that all DSM programs with a TRC (levelized $/MWh) greater than $110 will not be cost effective and should be terminated – having chosen $110/MWH as a cut-off as it is equal to the levelized cost of bids recently accepted by BC Hydro in the Bioenergy Call. JIESC identifies six such DSM programs purporting to save a total of 222 GWh in F2020 which it submits are not cost-effective and should be terminated (JIESC Argument, p. 21).

BC Hydro submits that not only has JIESC based its cost assumptions on inappropriate data, but also the two Sustainable Community programs that JIESC request be terminated have become more important following the recent passage of the *Local Government (Green Communities) Statutes Amendment Act, 2008* and represent a critical opportunity for the Sustainable Community programs to influence energy efficiency and conservation in municipal government planning (BC Hydro Reply, p. 65).

Commission Determination

The Commission Panel acknowledges JIESC's concern with the high cost programs in BC Hydro's DSM Plan and its request to disallow certain DSM programs having a UEC in excess of $110/MWh. The Commission Panel does not find BC Hydro's reliance on the *Local Government (Green Communities) Statutes Amendment Act, 2008* to be persuasive, noting that in circumstances where it is deemed by the government to be in the public interest for the Commission to set aside its discretion, the government can, and has in other circumstances exercised its authority through Special Directions to the Commission or by way of Regulation, but has not done so in this case.

That notwithstanding, the Commission Panel notes the relatively small expenditures BC Hydro is contemplating for these programs, and the modest benefits expected, and suggests to BC Hydro that the specific programs identified by JIESC should be subject to further management review before being proceeded with.

Accordingly, JIESC's request that the Commission direct the termination of all DSM programs with a TRC greater than $110/MWh is denied.

7.7.3 Amendment of F05/F06 RRA Decision Directives 62 and 64

As Endorsement (vii), BC Hydro requests that the Commission endorse an amendment of Directive 60 of the F05/F06 RRA Decision which directs BC Hydro to:

> "Seek approval for, and file tariffs for, all new Power Smart programs with a RIM benefit/cost ratio of less than 0.8 and/or a TRC benefit/cost ratio of less than 1.0. For those Power Smart programs with a RIM benefit to cost ration of less than 0.8, BC Hydro is directed to justify with each [long term resource plan] filing the continuation of such programs."

BC Hydro has requested endorsement of an amendment of this Directive to read: "seek approval for all new Power Smart programs with a TRC benefit/cost ratio of less than 1.0." This request is based on no proposed DSM program having a TRC benefit/cost ratio below 1.0 with the exception of those programs specified in subsection 4(2) of the M271 which provides for an adder for low income programs that allow them to meet the TRC benefit/cost test.

BC Hydro indicates that it uses the RIM test as one component of addressing DSM equity issues. While it calculates the RIM test to obtain information on the potential impacts of DSM initiatives on non-participants, it does not believe that the results of the RIM test alone provide an indication of the potential equity issues related to the overall DSM plan. It believes that equity is best viewed by understanding if the overall DSM plan provides a broad range of opportunities for all customers to participate and benefit from DSM (BC Hydro Argument, pp. 126-128).

BCSEA and CEC support this request (BCSEA Argument, pp. 3, 35; CEC Argument, p. 32).

JIESC submits that it is appropriate for BC Hydro to calculate and report RIM test values for all DSM programs as this could reflect that a program is not fair or in the public interest (JIESC Argument, p. 30).

Other Intervenors took no position on this issue.

Commission Determination

The Commission Panel approves BC Hydro's request to amend F05/F06 RRA Decision Directive 60 to read "seek approval for all new Power Smart programs with a Total Resource Cost ("TRC") benefit/cost ratio of less than 1.0."

With respect to the JIESC's request that RIM test values continue to be reported, the Commission Panel finds that that information is of value, and accordingly requires BC Hydro to continue reporting those values it so calculates.

7.7.4 DSM Amortization Period

As Endorsement (iv), BC Hydro requests the Commission endorse continuation of the ten year DSM amortization period. It submits that:

- it provides a proper matching of costs with the benefits, since the average persistence of energy savings from DSM programs is eleven years;
- it is consistent with Generally Accepted Accounting Principles;
- Commission Order G-55-95 allows an amortization period of up to ten years; and
- it compares favourably to the amortization period of several other utilities.

(BC Hydro Argument, pp. 130-131)

BCOAPO and BCSEA support the ten year amortization period (BCOAPO Argument, p. 18; BCSEA Argument, para. 117).

CEC submits that a longer period and that a more detailed assessment of the amortization period is in order (CEC Argument, p. 8), while TAN proposes a shorter period (no more than three years) (TAN Argument, p. 6).

Other Intervenors took no position on the amortization period.

BC Hydro submits that there is no evidence in the 2008 LTAP proceeding to support TAN's position, while there is evidence to support BC Hydro's proposal to continue amortizing DSM costs over a period of 10 years (BC Hydro Reply, p. 7).

Commission Determination

The Commission Panel finds that neither CEC nor TAN provided evidence to support their submissions and accordingly endorses the DSM amortization period remaining at ten years.

7.7.5 Amendment of F06/F06 RRA Decision Directive 60

As Endorsement (vi), BC Hydro requests the Commission to eliminate its F05/F06 Revenue Requirements Application Decision Directives 62 and 64 which relate to load displacement ("LD") projects being considered as supply side alternatives, and submits that these directives are no longer consistent with the new definition of demand-side measures in s. 1 of the *Act*. BCSEA supports this requested endorsement (BCSEA Argument, p. 3).

IPPBC opposes this endorsement, asserting that load displacement programs do not belong in the DSM program (IPPBC Argument, p. 28).

BC Hydro submits that IPPBC's rationale rests on the assertion that LD projects are not subject to any competitive bidding process or participation in standing offer programs, and that how projects are selected or whether they can participate in standing offer programs has no bearing on whether they should be considered DSM (BC Hydro Reply p.8).

Commission Determination

The Commission Panel finds that Directives 62 and 64 are no longer consistent with the definition of demand-side measures in section 1 of the *Act* which specifically provides that Load Displacement Measures are DSM. **Accordingly, the Commission Panel endorses the request to eliminate F05/F06 RRA Decision Directives 62 and 64**.

7.7.6 Voltage Optimization

Included in BC Hydro's portfolio of DSM programs but not in its expenditure request of $418.0 million, are two programs related to voltage optimization ("VO"), one residential and one commercial. While BC Hydro asserts that VO meets the *Act* definition of a demand-side measure, both IPPBC and JIESC contend that VO is not DSM.

IPPBC submits that when dealing with DSM, one is dealing with "demand," and "…not dealing with supply. And when we're dealing with voltage optimization, we're dealing with supply" (T16:2859). IPPBC also considers VO to be a "system upgrade or modification and is the same as any other investment in hardware" (IPPBC Argument, p. 28). Further, it states that no business plan has been provided with respect to VO, so it may not produce the desired effect. BC Hydro submits that this "is not a valid reason why VO should not be considered as a demand-side measure as defined by the *UCA*" (BC Hydro Reply, p. 68).

JIESC also states that categorizing VO as a demand-side measure is inappropriate. It submits that if VO were to be included as DSM, then "most other improvements to the Transmission System could also be included. In JIESC's submission, before something can properly be considered to be DSM it has to have something to do with the "demand-side or customer side of the business. Voltage Optimization does not" (JIESC Argument, p. 26). BC Hydro acknowledges that "DSM savings are at the customer meter and do not include savings attributable to transmission or distribution losses" (Exhibit B-1, p. 3-6). Furthermore, BC Hydro acknowledged that "whether it impacts the customer side of the meter is an appropriate test" (T16:2867).

BC Hydro provided a report of a study conducted by 13 utilities (The Northwest Energy Efficiency Alliance) that discusses voltage control as a means of reducing energy consumption. That report refers to the initiative as a Distribution Efficiency Initiative ("DEI") with the overall objective "to transform the distribution system market, supporting distribution engineers and utility management in adopting more efficient DEI strategies," and focuses on substations and feeders, and distribution system improvements rather than customer behaviour or demand-side measures

(Exhibit B-3, 1.167.2, Attachment 1).

Pursuant to Item 1 of Exhibit A-20, the Commission Panel invited further submissions on this matter in the Oral Phase of Argument.

BC Hydro, with reference to its Argument and Reply, submitted that the definition of what constituted DSM at section 1 of the *Act* was sufficiently broad so as to encompass VO as a DSM. BC Hydro referred to the "two branches" of the definition:

(a) to conserve energy or promote energy efficiency, and
(b) to shift the use of energy to periods of lower demand;

submitting that VO satisfies both tests as it "conserves energy and reduces the demand BC Hydro must serve on the customer side of the meter" (T16:2852-53).

CEC and BCOAPO support BC Hydro's position.

ESVI also supports BC Hydro, citing the report from 13 utilities referred to above which read, in part:

> "Operating a utility distribution system in the lower half of the acceptable range, 120 to 114 [i.e. volts], saves energy, reduces demand, and reduces reactive power requirements without negatively impacting the customer" (T16:2858).

IPPBC refers to BC Hydro's testimony in response to IPPBC's question as to what criteria BC Hydro used in determining what measures it included in or excluded from a DSM portfolio, which was: "So when we take a look at putting a DSM plan together, in this case we're taking a look at putting together a broad DSM plan … to make sure that we're doing our best to provide opportunities for a broad range of customers to participate." IPPBC submits that "at a bare minimum, DSM has to involve a customer" (T16:2859-60).

JIESC supports VO as a "system efficiency," but refers to its submissions in Argument that if VO were to be included as DSM, then "most other improvements to the Transmission System could also be included. In JIESC's submission, before something can properly be considered to be DSM it "should have an element of customer involvement." Further, it argues that all VO encompasses is "fixing some inefficiencies at a sub-station, settings that are higher than normal" and that "simply isn't DSM, that's just smart operations" (T16:2862).

TAN submitted that there is no "market mechanism that would enable voltage optimization to occur on the demand side" (T16:2863).

In reply, BC Hydro argues that the "reading-in" of the need for customer involvement by IPPBC and JIESC was incorrect, and that given its purpose to conserve energy and reduce the energy demand on the customer side of the meter, VO "squarely falls within the definition [of DSM]" (T16:2866).

Commission Determination

The Commission Panel notes the evidence that while VO programs do conserve energy and promote energy efficiency, and while they do reduce the energy demand that a public utility must serve, they are directed to the characteristics of the electricity supplied, and have no interaction with customer behaviours and choices.

The Commission Panel gives particular weight to the Northwest Energy Alliance report cited in the Oral Phase of Argument by ESVI, and referenced in its Final Argument by BC Hydro. That report refers to the voltage control initiative as an initiative, whose overall objective was "to transform the distribution system market, supporting distribution engineers and utility management in adopting more efficient DEI strategies." Its focus is on substations and feeders, large utilities, and distribution system improvements. It makes no reference to customer behaviour or demand-side measures as such.

For these reasons, the Commission Panel finds that while VO programs might "technically" meet the criteria for DSM, the classification of VO programs as DSM would unhelpfully "blur" the distinction between transmission and distribution system efficiency enhancement initiatives that should be being taken by BC Hydro in the normal course, and its DSM programs. Accordingly the Commission Panel determines that VO programs are not DSM initiatives.

The Commission Panel encourages BC Hydro to bring an MTP application for its VO programs forward in the normal course, and expects that that application will be supported by a business case validating the cost-effectiveness of its proposal.

7.7.7 Relief Sought By Terasen

7.7.7.1 Context

The choice of energy source for space and water heating applications, particularly in a residential context has been a matter of considerable debate and contention in recent proceedings before the Commission. In BC Hydro's 2007 Rate Design Application ("2007 RDA"), the seasonality of residential electrical energy demand and consumption was clearly established as the principal factor establishing BC Hydro's electricity supply parameters for its integrated system. The material degree to which this seasonality impacted residential customers' bills was canvassed at length in the review of BC Hydro's 2008 Residential Inclining Block rate structure ("RIB") application. Most recently, in its review of Terasen's 2009 Energy Efficiency and Conservation ("EEC") Application the Commission was asked, but declined, to deal with the matter of energy choice in a determinative fashion. In that proceeding, the Commission found that "the optimal balance as between natural gas and electricity had not been established" on the evidentiary record, and that that record was insufficient to conclude that "a regional approach should be adopted as a justification for EEC expenditures aimed at substituting natural gas for electricity" (Terasen Argument, p. 21).

The issue is not unique to BC, and has been constructively dealt with in other jurisdictions. In BC, its resolution is more complex as it is impacted by various government policy statements, along with statutory and regulatory directions. From these instruments, parties who have joined the debate are generally able to find support for their particular point of view. To date, there has appeared little, if any, consensus as to how the matter could, or should be resolved absent further direction from the provincial government.

Not surprisingly, given the disproportionate impact of residential space and water heating applications on BC Hydro's forecast load and capacity requirements, the matter was the again subject of extensive evidence, cross-examination, and argument in this LTAP proceeding.

7.7.7.2 Terasen's Position

In its Argument Terasen has endeavored to crystallize the issue by focusing on what it describes as Electric Load Avoidance ("ELA") DSM, being the provision of cost-effective incentive payments to customers faced with a decision to install new, or replacement appliances for which alternatives to electricity are available, in order to encourage customers not to adopt electricity where electricity is not the most efficient energy source from a TRC perspective.

Terasen acknowledges BC Hydro's apparent willingness to study the further potential for ELA DSM and seeks to have the Commission "identify the key parameters of that initiative through its findings and directions in this proceeding. Specifically, Terasen requests that the Commission "require BC Hydro to file its next LTAP within 12 to 15 months" of its Decision in this proceeding, and that it direct BC Hydro "include in its next LTAP a proposal to pursue cost-effective ELA DSM based on the outcome of its further study" (Terasen Argument, p. 3).

Terasen cites BC Hydro's acknowledgment of the Commission's jurisdiction to direct a study of ELA DSM, and requests that certain directions be given to BC Hydro to guide that work, including that:

- the cost effectiveness of ELA DSM should be determined with reference to the TRC test;
- in that analysis an updated avoided cost (before line losses) of at least \$120/MWh should be used, time-of-delivery weighted per Exhibit B-73 in the case of space heating load;
- cost-effective measures should not be eliminated based on a simple payback analysis using current rates; and
- part of the study must explore different incentive models within the framework of ELA DSM. (Terasen Argument, p. 42)

Terasen founds its submission in part on:

- the statement in the BC Energy Plan that "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas";
- the legislated requirement in the *Act* that cost-effective DSM must be pursued before the acquisition of new higher-cost supply to meet any residual load/resource gap, which Terasen submits that ELA DSM with a TRC benefit/cost ratio greater than 1 will achieve; and
- the government's energy objective, enshrined in the *Act* "to encourage public utilities to reduce greenhouse gas emissions," which Terasen submits that cost effective ELA DSM will achieve on a regional basis (Terasen Argument, p. 1-4).

Terasen submits that using the TRC test to assess the cost-effectiveness of ELA DSM is consistent with the M271. That regulation references TRC as a measure to determine cost-effectiveness in respect of particular DSM programs and requires the Commission to use BC Hydro's avoided cost of supply for assessing the cost-effectiveness of measures taken by entities that receive service from BC Hydro. Terasen notes that in its recent decision on Terasen's EEC Application, the Commission "endorsed the use of the TRC test more generally" (Terasen Argument, p. 15).

Terasen references the 2007 CPR, noting that, at an avoided cost of energy of \$88/MWh (based on the F2006 Call), the economic potential (TRC Benefit /Cost => 1) of ELA DSM was found to be 6,674 GWh/year by 2026 with the then current gas cost regime, and 3,293 GWh/year by 2026 under the forecast high gas cost regime. This potential was for the aggregate use of natural gas as an alternative fuel in the residential, commercial and industrial sectors. The conclusions of the 2007 CPR included:

> "[u]nder the Current supply cost forecast, there are a number of fuel-switching measures…that have a positive Measure TRC [i.e., TRC for the measure expressed in dollars is positive] and a Measure Benefit/Cost ratio that is equal to or greater than one. This result suggests that from a provincial economic perspective, there are opportunities where switching from electricity to natural gas may be beneficial. (Terasen Argument, p. 16)

Terasen updates the findings of the 2007 CPR as to the economic potential of ELA DSM using the "proxy" for BC Hydro's current marginal cost of new supply as recorded in this proceeding at \$120/MWh, and Terasen's current combined commodity and mid-stream charge to the Lower Mainland of \$8.551 per GJ. Terasen concludes that, even with the inclusion of the Carbon Tax, "as \$8.551/GJ is less than one third the cost of BC Hydro's avoided cost of supply there is a sufficient margin to allow for this and still yield a favorable TRC." Terasen points out that a cost of \$120/MWh corresponds to an equivalent gas cost of \$30.00/GJ (Terasen Argument, p. 18).

Terasen explains that the 2007 CPR "did not identify any *achievable potential* for [ELA DSM] because customers paying rates that reflect the low embedded cost of electricity do not see the "payback" necessary from these measures to consider adopting another energy source." Terasen reiterates its concern as expressed in its role in the CPR stakeholder process (see Section 4 of this Decision) about eliminating measures based on payback established with reference to rates based to a significant extent on embedded costs, and submits that "BC Hydro has a responsibility to its customers to identify incentive models to turn the identified *economic potential* into *achievable potential"* (Terasen Argument, p. 19).

Terasen submits that the pursuit of cost-effective ELA DSM will result in reduced electric load in BC, and that renewable power generated in BC that is surplus to the domestic load requirements in any one time period will be exported into the Western Interconnection. Terasen notes that as over 80 percent of the time the marginal source of electricity supply in the Western Interconnection is from natural gas- or coal-fired generation facilities, the injection of BC renewable power will displace such existing, or new generation. Terasen argues that since modern domestic gas furnaces and hot water heaters operate at between 85 - 90 percent efficiency compared to current CCGT generators which operate at 50 percent efficiency, and to coal-fired generation at even lower efficiency, material reductions in regional GHG emissions will result. Terasen quantifies these benefits as a reduction from 360 tonnes GHG/GWh for a CCGT to 200 tonnes GHG/GWh for a high efficiency gas furnace (Terasen Argument, pp. 22-23).

Terasen submits that BC Hydro's reluctance to pursue cost effective ELA DSM on the basis that it is "awaiting a clearer government directive" is not appropriate. Terasen argues that the government's neutral position on energy choice is not a "policy void," but is in fact in accordance with the emphasis in the Energy Plan on "the importance of making efficient choices among energy sources available for particular end uses" (Terasen Argument, p. 31).

Terasen further submits that BC Hydro's "implicit suggestion that pursuing cost-effective ELA DSM would require BC Hydro to be pro-natural gas" is not correct. Terasen argues that such DSM would act "in conjunction with the existing conservation rate structure to *counteract* the fact that electricity rates based on embedded costs encourage customers to adopt electricity as an energy source where the TRC analysis demonstrates that electricity is not the most efficient fuel alternative for particular end uses." Terasen further submits that nothing in its proposal limits the customer to choosing between, for example, electric baseboard heating or natural gas heating, that in fact cost-effective ELA DSM could well encompass other alternatives such as heat pumps (Terasen Argument, p. 33).

Lastly, Terasen notes "BC Hydro's interpret[ation] of the provincial emissions target in the *GGRTA* as a prohibition against pursuing cost effective ELA DSM, at least insofar as the alternative fuel is natural gas." Terasen submits that BC Hydro's "Electric Load Avoidance analysis unjustifiably elevates to the status of ultimate objective one *means* by which government has chosen to pursue its ultimate objective of mitigating climate change associated with GHG emissions." Terasen submits that the Province has used other legislation to achieve its climate change objectives, in particular the relationship of the objective enshrined in the *Act* to "encourage public utilities to reduce [GHGs]" with the Province's membership in the WCI. Terasen further notes the government's promotion of natural gas development in the Province, as reflected in the Energy Plan, and submits that while the production of natural gas contributes 18 percent of BC's total GHG emissions, it is nonetheless "better from a climate change perspective to produce and consume natural gas anywhere in the WECC region for direct use applications or for gas-fired generation than it is to generate electricity using a higher emitting energy source such as coal. Coal generation emits about twice the amount of GHG per GWh than does natural gas-fired generation." In sum, Terasen submits that "These initiatives illustrate the need to balance government's interest in reducing GHG emissions against other competing objectives" (Terasen Argument, pp. 35-38).

7.7.7.4 Intervenors' Positions

In respect of Terasen's anticipated request for relief, several Intervenors commented as follows.

JIESC submitted that "while the debate is interesting, and will undoubtedly play a large roll [sic] in future LTAP proceedings, in JIESC's position it is premature at this time." JIESC notes that the government did not make a declaration as to "natural gas or electricity as the fuel of choice for a particular application….in the Energy Plan or otherwise," and that "Until the government declares its views, neither BC Hydro nor the Commission should deliberately promote one fuel over the other." (JIESC Argument, p. 11)

CEC submitted that "BC Hydro has accurately summarized the evidence on fuel switching and that unless and until the Province clearly directs the approach to fuel switching in British Columbia, there will be a high level of uncertainty for ratepayers as to where long term planning at BC Hydro and Terasen should be directed." CEC also submitted that it "does not entirely agree with BC Hydro's submission that the evidence is clear that fuel switching from electricity to natural gas will increase GHG within BC…" noting that while "that is a reasonable conclusion to draw at this time" that "the uncertainty in this area is material and further justifies a cautious approach by the Commission in terms of providing any long term commitments by BC Hydro based on assumptions around fuel switching where such a high level of uncertainty exists." (CEC Argument, p. 14)

BCOAPO refers to the Commission's Decision in Terasen's EEC Application, noting that the Commission:

- "rejected the notion that natural gas for space and water heating was proven to be part of the optimal balance, or even that there was enough evidence on record to find that natural gas was a more efficient energy source than electricity in those applications";
- "noted the increase in GHG emissions that would occur from such fuel switching"; and
- "acknowledged the government's GHG reduction policy, stating that [Terasen] had not presented sufficient evidence in that process to persuade [the Commission] that a regional approach should be adopted."

BCOPAO submits that, from its perspective, "there is far less evidence on these points on the LTAP evidentiary record and they are no more persuasive here than they were in [Terasen's] own EEC application" (BCOAPO Argument, p. 8).

In supporting BC Hydro's rejection of Terasen's submissions, BCOAPO also notes the implications of the M271, which at section 1, specifically excludes "a program to increase the amount of energy sold or delivered by the public utility" from the permissible ambit of 'a public awareness program,'" effective June 1, 2009. BCOAPO submits that "the entire thrust of Terasen's case in this proceeding can be seen as an effort to end-run the Regulation," "to seek to compel the ratepayers of another utility – BC Hydro – to do what they cannot do for themselves" and "to do indirectly what is prohibited directly" (BCOAPO Argument, p. 9).

IPPBC supports BC Hydro's arguments in respect of fuel switching from electricity to natural gas (IPPBC Argument, p. 52).

TAN submits that "It is abundantly clear to us that using gas in a domestic appliance at 90% efficiency is far more efficient than using Burrard Thermal at 30% efficiency, and buying carbon offsets" and further, "Encouraging fuel switching would be the easiest means available in terms of meeting the output gap particularly when the BC Hydro demand profile is heavily skewed to peak space heating demand from residential and commercial customers" (TAN Argument, p. 5).

BCSEA extensively analyses the issues surrounding both "electrification" of applications presently using natural gas as an energy source, and the potential for improvement in energy efficiency by using natural gas in space and water heating appliances. Among other points, it submits that:

- "where an electrification measure is *less* energy efficient than a more carbon-intensive alternative, determining which involves fewer GHG emissions may require both quantitative and policy analysis, regarding both the short term and the long term" (BCSEA Argument, p. 16);
- it "disagree[s] with BC Hydro's comment to the effect that advocates of electricity to natural gas fuel-switching programs by BC Hydro assert that 'BC Hydro should intentionally incent people to de-electrify and in doing so increase their personal carbon footprint'" as being an unfair characterization of the objectives of such proposals (BCSEA Argument, p. 18);
- it notes that "a fossil-fuel to electricity fuel switching program by BC Hydro (electrification) would involve a similar potential for making BC Hydro 'complicit' in the customer's choice of fuel type (BCSEA Argument, p. 24); and
- it notes that "while electrification as a GHG emissions reduction tool is mentioned in the 2007 Energy Plan the major thrust in the Energy Plan, the amendments in the *Act* and BC Hydro's LTAP concerns demand side-measures intended to *reduce* electricity consumption (and peak load) rather than to *foster* electricity consumption in order to reduce net carbon emissions" (BCSEA Argument, p. 21).

In sum, while BCSEA "take[s] a position *against* electricity to natural gas fuel switching programs by BC Hydro in this LTAP," it agrees that suitable treatment of electricity to gas and gas to electricity fuel switching in the next LTAP will require new analysis by BC Hydro, that such analysis should proceed whether or not government policy on the topic is forthcoming, and that BC Hydro should lead a "Fuel Switching Analysis" dialogue with stakeholders (BCSEA Argument, pp. 26, 18-19).

7.7.7.5 BC Hydro's Position

In its Reply, BC Hydro submits that the Commission should not accommodate Terasen's request for express directions to "frame the study" i.e., BC Hydro's Fuel Switching Analysis, as it would "virtually [be] pre-ordaining the outcome" for the following reasons:

- BC Hydro's proposal is "a planning study," and arbitrary limitations on input assumptions may have unintended consequences that bias the results and negate any meaningful value resulting;
- the Commission "would be falling into legal error" as it would be fettering its discretion with respect to the review of a component of the next BC Hydro DSM Plan;
- such directions "[would] inappropriately elevate [Terasen's] views on the scope of the Fuel Switching Analysis above those of BC Hydro and its customer Intervenors]"; and
- Terasen's requested directions do not accord with the Decision in the Terasen EEC Application as that Decision conflicts with Terasen's position that the GGRTA does not and should not prevent BC Hydro from pursuing' fuel switching from electricity to natural gas. (BC Hydro Reply, pp. 22-23)

BC Hydro requests that it be directed to "undertake a Fuel Switching Analysis examining the cost effectiveness of both fuel switching from electricity to natural gas, and from natural gas to electricity, and report back on the results as part of its next DSM plan filed with the Commission". BC Hydro submits that Terasen is at liberty to "do their own study, using whatever stakeholder processes they may or may not choose to use, and prepare and file their own evidence in BC Hydro's next LTAP proceeding" (BC Hydro Reply, p. 23).

BC Hydro supports its position with extensive submissions in its Reply and with reference to its considerable and detailed submissions on the same matters in its Final Argument.

In particular, BC Hydro submits that Terasen provided no evidence except through "so called 'witness aids' providing dated and/or untested documents and no opportunity for Intervenors or BC Hydro to test the veracity of the materials …" and that Terasen relies selectively on prior Decisions of the Commission, which have no precedential value. BC Hydro notes that only BCSEA provided evidence, and witnesses, on the subject of fuel switching. It disputes that evidence and testimony as it relates to the short term impact of electricity to natural gas fuel switching on regional GHG emissions, and notes that "[d]espite Mr. Plunkett's evidence BCSEA *et al*, in its submissions, accepted BC Hydro's argument that there would be no short-term GHG emission impact" (BC Hydro Reply, p. 26).

BC Hydro also argues that within the medium to long term its net supply/demand balance and the amount of electricity it would have available for export would be unchanged as "the marginal resource is located within BC and because BC Hydro cannot build for export," and that that position is uncontested (BC Hydro Reply, p. 28).

In respect of Terasen's linkage of the GHG costs incurred by natural gas space heating to BC Hydro's consumption of natural gas at Burrard, BC Hydro states that that is irrelevant as its "plan to rely on Burrard would not change as a result of customers switching from electricity to natural gas as their fuel for space heating." And further, BC Hydro submits that "…nor would the operation of Burrard have any substantive change in the expected energy production as a result of any shift in the proportion of heating load served by gas or electricity" (BC Hydro Reply p.29).

BC Hydro addresses Terasen's assertion that "the GGRTA does not inhibit BC Hydro from pursuing fuel switching from electricity to natural gas" by referring to the "considerable uncertainties related to the Province's GHG emission reduction targets" as accepted by the Commission in Terasen's EEC decision. BC Hydro submits that those uncertainties "continue to be the case" (BC Hydro Reply p. 30).

Commission Determination

By way of context, the Commission Panel finds that Terasen's description of its proposed DSM as a "Load Avoidance" scheme is both useful and helpful in the Commission Panel's understanding of the issues. The generic "fuel switching" parlance seems to lead to confusion as to the nature of the issue, and to unhelpfully broaden the scope of the debate into unrelated areas, such as “electrification” to meet other objectives projected or postulated by the parties.

The Commission Panel views the matter of ELA DSM targeted to space heating applications in general, and residential customers in particular as being legitimately before it in the context of this LTAP proceeding since:

- it is well settled from prior proceedings before the Commission, and re-confirmed in this proceeding that heating-related seasonal residential loads are a determinant in the quantum and shape of BC Hydro’s capacity and demand history and its forecasts for growth (T6:875; and T11:1946);
- the paramouncy of cost-effective DSM in BC Hydro’s planning for future growth is recognized by statute; and
- it is equally recognized by statute that analogous “Load Displacement” programs are DSM for the Commission’s purposes in establishing the gap remaining between BC Hydro’s mid-range Load Forecast, net of cost-effective DSM, and the capability of its Heritage assets, which BC Hydro seeks to fill with new supply.

In terms of certain of the matters that BC Hydro and others say should influence the Commission Panel’s determinations in the matter of ELA DSM as proposed by Terasen, the Commission Panel notes that the record in this proceeding is clear that:

- BC Hydro intends to continue to source electricity from natural gas fired generation from Burrard and the Island Cogeneration Project in its integrated network, and to expand its gas-fired generation at its Fort Nelson plant and continue to rely on that plant even if the Fort Nelson area becomes a part of its integrated network;
- all else equal, there is a material reduction in GHG emissions to the degree that reliance on those sources is reduced by direct application of natural gas for high-efficiency heating applications that would otherwise be met with electrical energy;
- notwithstanding BC Hydro’s position that it does not have a mandate to “build for export,” its implementation of its plans to achieve compliance with SD10 over time leads to a materially large “structural surplus” ranging up to 13,000 GWh/year in BC Hydro’s supply/demand balance in all years except for those affected by some combination of adverse events including a “critical low water sequence,” the inevitability and/or timing of which is unknown (T12:2287);
- that surplus, absent BC Hydro idling its generation facilities, will be exported into the WECC;
- to the degree that BC Hydro acquires long term “BC Clean” electricity supply through EPA’s

in order to meet the SD 10 planning criteria, with or without Commission endorsement, that surplus supply is projected to be at higher marginal cost than supply from any of its Heritage assets, or available from the market (to which BC Hydro's access continues to be unfettered (T7:1064); and,

- to the degree that exporting that structural surplus offsets the need for marginal electricity supply in the WECC from coal or natural gas fired generation, whether it be on a transitory or medium- to long-term basis, a net reduction in GHG emissions results.

The Commission Panel notes that, notwithstanding BCSEA's stated opposition to Terasen's ELA DSM proposal "at this time," its intervenor evidence and its witnesses' testimony directly supported many of the above points as shown in the following exchanges between BCSEA witnesses and cross-examining counsel:

Mr. Godsoe: Q. "So I'm curious as to how you can say the Commission should formulate guidelines for fuel switching, when the government has a stated policy now, which is neutrality,"

Mr. Hackney: A. "Well, we see the clear evidence that fuel switching could have a net effect in reducing greenhouse gas emissions. We regard that as being very important. What we see in BC Hydro's testimony here and elsewhere was speaking to rejecting fuel switching on the basis that it would cause greenhouse gas emissions inside of BC, yet we all know the effect is the regional, indeed the global area for greenhouse gas emissions" (T12:2147).

And further,

"Mr. Fulton: Q. "And you conclude the paragraph with the opinion that 'Consequently cost-effective electric to gas fuel switching in BC will result in decreased greenhouse gas emissions.' And do I take it you still stand by that statement?"

Mr. Plunkett: A. "I do" (T12:2166).

The Commission Panel notes that BCSEA's objection to Terasen's proposal is qualified by being "at this time," and is primarily founded on the "confusing signals" that might be given to customers. Given the importance to those who receive, or may receive service from BC Hydro of ensuring that all cost effective DSM is in fact reflected in BC Hydro's electricity supply obligations, the Commission Panel gives that argument little weight.

The Commission Panel similarly gives little weight to BCOAPO's submissions which characterize Terasen as attempting to "end-run" certain aspects of the 2008 DSM Regulation. The section that BCOAPO cites deals with "a public awareness program" and would equally inhibit any electric utility from advancing a program to increase "electrification" in applications for which alternative energy sources are available.

The Commission Panel finds that a primary basis for BC Hydro's objections to Terasen's ELA DSM proposal is BC Hydro's interpretation of the *GGRTA* as precluding any consideration of capturing the seemingly un-contreverted, and potentially material, benefits of such a load avoidance program. The Commission Panel believes that view to be unreasonable, as it is unsupported by any evidence that that *GGRTA* limits any particular activity involving the generation of GHGs, but rather it speaks to overall, aggregated GHG emissions in the Province, and sets targets for their future level.

In particular the Commission Panel notes that by BC Hydro's own reckoning, natural gas is expected to capture the majority of the future demand for residential space and water heating applications, all of which would "increase the emissions of GHG within the Province" and notes that the BC Government has taken no policy or statutory steps to limit or otherwise curtail that demand beyond the *Carbon Tax Ac*t at this time. That Act equally applies to natural gas used for electricity generation as well as to that for such direct applications as space and water heating, and as well, to all other non-renewable carbonaceous fuels. It's economic consequences are known, and are readily incorporated into the calculations necessary to quantitatively establish the cost of and benefit of a load avoidance measure such as Terasen's proposed ELA DSM. Similarly, the legislated requirement for GHG offsets for gas-fired electrical generation can be estimated and included in such calculations.

For these reasons, the Commission Panel finds that without a quantification of the cost-effectiveness of an adequate ELA DSM program such as proposed by Terasen it is not possible to conclude that BC Hydro has included all cost-effective DSM in its electricity supply obligations, as defined by SD 10, in this LTAP. It is equally clear that, without resolution of this matter, its next LTAP will be similarly compromised.

Accordingly, while BC Hydro is at liberty to do whatever other studies it chooses, and provide whatever evidence it feels is appropriate in its next LTAP Application, the Commission Panel specifically requests that BC Hydro do, and present as a discrete element, the necessary analysis to establish the cost-effectiveness, or lack thereof, of DSM programs to achieve the apparent economic potential of Electric Load Avoidance DSM for space and water heating applications in new residential construction (including multiple unit dwellings) and new small commercial applications. That analysis should focus on high efficiency natural gas fired appliances compared with electrical baseboard heating applications. For the purposes of this analysis "new construction" is to include major renovations to existing structures heated in whole or in part by electric baseboard heaters.

While it is BC Hydro's choice as to how it conducts this analysis, and which parties it elects to involve, the Commission Panel strongly suggests that it be done in conjunction with Terasen. The Commission Panel notes the testimony of BCSEA's expert witness Mr. Plunkett at T12: 2173-80 as to the benefits of collaborative management by electric and gas distribution utilities in various US jurisdictions in achieving more efficient overall energy use in those jurisdictions.

8.0 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 NO.
1	The Commission Panel accepts the price forecasts for natural gas, electricity, and GHGs, and RECs for purposes of the 2008 LTAP.	29
2	The Commission Panel finds that the definition of "capability" from the 2004 IEP is appropriate for the purposes of this LTAP. In other words, what a unit is capable of contributing to BC Hydro's electricity supply obligation is to be determined by its design capacity under specified conditions over a period of time, typically a year – the "engineering exercise" as described by BC Hydro, and referenced in Section 6.2.4 of this Decision.	44
3	The Commission Panel rejects that part of the 2008 LTAP that concerns energy and capacity self-sufficiency.	45
4	In its next LTAP, BC Hydro is requested to pay particular attention to the phasing in of the steps it deems necessary in order to meet the two aspects of self-sufficiency specified by SD 10. Particular regard should be given to achieving the requirements in a manner that meets the requirement of having the capability "within the Province," while avoiding any undue burden on its ratepayers.	45
5	The Commission Panel recognizes the potential for both over-statements and under-statements in the 2008 Load Forecast Update, it rejects CEC's request to provide the Commission as soon as possible with an updated load forecast.	54
6	The Commission Panel accepts BC Hydro's 2008 Load Forecast Update for the purposes of its review of the 2008 LTAP. The Commission Panel also notes that BC Hydro agrees with IPPBC that there is some potential for double counting of DSM in the forecasting coefficients and requires BC Hydro to address this in its next LTAP.	54

7	The Commission Panel requires BC Hydro in its next LTAP to provide in tabular and graphical form at least ten years of past actual consumption by four classes of customer – Residential, Small Commercial, Large Commercial, and Industrial - and the resultant total demand thereof. It also requires the provision of the 20-year projection of the statistical best fit extension of that data based on a simple linear regression of loads and a time trend. This should be separate from its own projections of demand for those classes and the total thereof for the same forward 20-year period. BC Hydro is required to explain the factors used as inputs to its forecast that may cause any differences between its forecasts, and the statistically derived "base line forecasts" for several snapshots in time during the 20-year forecast for each of its customer classes.	55
8	The Commission Panel denies IPPBC's request to re-open the record to hear more evidence on EPVs as it considers that the issue was adequately canvassed during the proceeding.	55
9	The Commission Panel finds that acceptance of, and/or undue weighting of, any particular prescriptive criteria for cost-effectiveness advanced by BC Hydro or any Intervenor would unduly fetter its discretion to make such determinations within the context of this proceeding. The Commission Panel will make its determinations based on the evidence before it.	71
10	The Commission Panel agrees with BC Hydro and finds that when comparing the UEC of a DSM program with the UEC of a supply-side option, the appropriate metric upon which to compare levelized $/MWh is the TRC.	72
11	The Commission Panel requires BC Hydro to address in its next LTAP a methodology for comparing risk-weighted UECs of demand side measures and of physical supply-side resources.	72
12	The Commission Panel has concluded that BC Hydro has not met the statutory burden it acknowledged the *Act* requires. Accordingly, the Commission Panel finds that it is unable to determine the DSM Plan as proposed by BC Hydro complies with section 44.1 of the *Act*.	85
13	Inasmuch as BC Hydro has effectively chosen to truncate its DSM programs in F2020 by letting the impact of those programs progressively decay, the Commission Panel finds that BC Hydro's DSM Plan is deficient.	86
14	The Commission Panel endorses BC Hydro's plan to rely on Burrard for planning purposes for 900 MW of capacity.	114

15	The Commission Panel declines to endorse BC Hydro's proposal to reduce its reliance on Burrard for planning purposes to 3,000 GWh/year for the purposes of this LTAP. Accordingly, the Commission Panel only endorses the part of BC Hydro's request for Endorsement (iii) to rely on Burrard for 900 MW of capacity.	115
16	Given its previous determination in respect of the role of Burrard, the Commission Panel sees no reason to reject BC Hydro's request for approval of expenditures of $1.6 million in F2010 for sustaining capital to ensure the reliability of Burrard, and accordingly approves the expenditures as being in the public interest.	117
17	The Commission Panel declines to endorse BC Hydro's proposed target from the 2008 CPC of either 3,000 GWh/year gross or 2,100 GWh/year net.	124
18	The Commission Panel endorses the clean or renewable eligibility of the 2008 CPC request for relief given the government's energy objectives.	124
19	The Commission Panel declines to endorse an attrition rate of 50 to 60 percent as requested by NaiKun.	126
20	The Commission Panel cannot find that the requested $2.0 million in F2009 and F2010 to complete the definition work and implement the 2008 CPC is in the public interest, and the request is denied.	127
21	The Commission Panel finds that there is insufficient evidence before it on this issue and accordingly denies CEC's request that it direct BC Hydro to introduce options into its IPP commitments.	128
22	The Commission Panel believes that the parts of the LTAP it has rejected represent a level of individual and collective materiality that removes the underpinnings of the entire 2008 LTAP. Accordingly the Commission Panel finds that BC Hydro's 2008 LTAP is not in the public interest and rejects it.	131
23	In terms of its next LTAP, the Commission Panel requires BC Hydro to present its electricity supply obligations and its plan for acquiring supply-side resources, if any, for a minimum period of 20 years and in accordance with the self-sufficiency criterion of section 3 of SD 10.	131
24	The Commission Panel approves the Contingency Resource Plans for inclusion in BC Hydro's Network Integrated Transmission Services update to BCTC pursuant to the Commission's Directive 3 of Order G-58-05.	136

25	The Commission Panel accepts BC Hydro's position that it is proceeding in accordance with the stated action plans and objectives of the 2007 Energy Plan, and accepts that Site C is a suitable resource option to be considered in BC Hydro's long-term planning process. The Commission Panel finds that the expenditures of $41 million on Stage 2 are in the public interest.	139
26	The Commission Panel declines to endorse BC Hydro's approach to filing its Capital Plans, on the basis that it contributes little if anything to improved regulatory efficiency.	145
27	JIESC's request for an MTP threshold of $10 million for IT and building projects is rejected by the Commission Panel as JIESC has provided no evidentiary basis for it.	145
28	JIESC's request, concurred with in principle by CEC, that programs consisting of individual projects, as defined by BC Hydro, which are linked in functional and/or geographic terms and in which the aggregate of the individual projects achieves the MTP threshold of $50 million within a three year spending period constitute a MTP and be subject to a MTP review, is acceptable to the Commission Panel as being consistent with the practice of other public utilities under the Commission's jurisdiction.	145
29	IPPBC's request that all BC Hydro's MTP review applications be by way of a CPCN Application under section 45 of the *Act* is rejected by the Commission Panel, as IPPBC has provided no alternative authorities to refute that which supports BC Hydro's view that such a policy would in fact be tantamount to the Commission fettering its discretion.	145
30	IPPBC's request that BC Hydro not bring forward for review MTPs that have not been formally approved by its Board of Directors is accepted by the Commission Panel as being in accordance with proper corporate governance principles and practices.	145
31	The Commission Panel declines to provide BC Hydro with prescriptive guidance as to how it should file its capital plans for review, other than that they should be filed as part of an LTAP proceeding. As to the form of, and proceeding in which it files its MTP applications, the Commission Panel requests that, at its earliest convenience but in any event no later than 6 months from the date of this Decision, BC Hydro file with the Commission a set of guidelines within which it is prepared to make MTP filings and applications and that that set of guidelines reflect such consultations with its Intervenors and Commission staff as BC Hydro deems appropriate.	148

32	The Commission Panel determines that BC Hydro's next LTAP filing should be on or before June 30, 2010.	151
33	The Commission Panel finds that the expenditure schedule of $418.0 million to implement DSM Plans generally as described in BC Hydro's Adjusted Option A in F2009, F2010, and F2011 is in the public interest pursuant to subsection 44.2(3) of the *Act* and is accordingly approved.	152
34	The Commission Panel finds that there is no evidence before it on which to base an instruction to BC Hydro to increase Option A expenditures by $46.0 million as requested by CEC. The Commission Panel denies CEC's request for that relief.	152
35	The Commission Panel determines that expenditures of $600,000 in F2009 and F2010 for definition work for capacity-related DSM are in the public interest and approves BC Hydro's Primary Relief #2 (b).	154
36	The Commission Panel endorses the filing of DSM performance reports on an annual basis going forward. BC Hydro is directed to file its report for the year ended March 31, 2009 with the Commission on or before September 30, 2009. In succeeding years it should endeavour to file its annual report on a timelier basis with June 30 of each year as a target. As a transition measure, BC Hydro is directed to file its last semi-annual report, for the period ending September 30, 2009, by no later than March 31, 2010.	155
37	The Commission Panel has already made its determinations under section 44.1 of the *Act* in respect of the DSM plan in Section 6.4 of this Decision and JIESC's request for relief is accordingly denied.	156
38	With respect to the content of BC Hydro's DSM reports, the Commission Panel finds that, given the statutory profile of DSM, and the material consequences to ratepayers of the results of BC Hydro's initiatives, these reports should include metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective.	156
39	The Commission Panel declines to grant JIESC's request to direct BC Hydro to enhance its industrial DSM incentives and to hold a Call for Tenders for Industrial DSM.	158
40	JIESC's request that the Commission direct the termination of all DSM programs with a TRC greater than $110/MWh is denied.	159

41	The Commission Panel approves BC Hydro's request to amend F05/F06 RRA Decision Directive 60 to read "seek approval for all new Power Smart programs with a Total Resource Cost ("TRC") benefit/cost ratio of less than 1.0."	160
42	With respect to the JIESC's request that RIM test values continue to be reported, the Commission Panel finds that that information is of value, and accordingly requires BC Hydro to continue reporting those values it so calculates.	160
43	The Commission Panel finds that neither CEC nor TAN provided evidence to support their submissions and accordingly endorses the DSM amortization period remaining at ten years.	162
44	The Commission Panel endorses the request to eliminate F05/F06 RRA Decision Directives 62 and 64.	162
45	The Commission Panel finds that while VO programs might "technically" meet the criteria for DSM, the classification of VO programs as DSM would unhelpfully "blur" the distinction between transmission and distribution system efficiency enhancement initiatives that should be being taken by BC Hydro in the normal course, and its DSM programs. Accordingly the Commission Panel determines that VO programs are not DSM initiatives.	166
46	In its next LTAP Application, the Commission Panel specifically requests that BC Hydro do, and present as a discrete element, the necessary analysis to establish the cost-effectiveness, or lack thereof, of DSM programs to achieve the apparent economic potential of Electric Load Avoidance DSM for space and water heating applications in new residential construction (including multiple unit dwellings) and new small commercial applications. That analysis should focus on high efficiency natural gas fired appliances compared with electrical baseboard heating applications. For the purposes of this analysis "new construction" is to include major renovations to existing structures heated in whole or in part by electric baseboard heaters.	179

DATED at the City of Vancouver, In the Province of British Columbia, this 27th day of July 2009.

Original signed by:

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A.J. Pullman
Panel Chair/Commissioner

Original signed by:

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R.J. Milbourne
Commissioner

Original signed by:

____

M.R. Harle
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-91-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
for the Approval of the 2008 Long-Term Acquisition Plan

BEFORE: A.J. Pullman, Panel Chair/Commissioner
R.J. Milbourne, Commissioner
M.R. Harle, Commissioner

July 27, 2009

O R D E R

WHEREAS:

A. On June 12, 2008 British Columbia Hydro and Power Authority ("BC Hydro") filed, pursuant to subsections 44.1(2), 44.1(4) and 44.2(1) of the *Utilities Commission Act* (the "Act"), the 2008 Long-Term Acquisition Plan ("2008 LTAP," "Application") with the British Columbia Utilities Commission (the "Commission") for review; and

B. The 2008 LTAP (Exhibit B-1) is a long-term resource plan for acquiring demand-side and supply-side resources to meet demand in British Columbia. The 2008 LTAP both updates and expands the 2006 IEP/LTAP, which was the subject of Order G-20-07 ("2006 IEP/LTAP Decision"); and

C. The 2008 LTAP reflects BC Hydro's commitment to examine the effects of the British Columbia Government's updated energy policy, "The BC Energy Plan: A Vision for Clean Energy Leadership," and the relevant issues in the 2006 IEP/LTAP Decision; and

D. The relief sought by BC Hydro is set out in Exhibit B-1-11, as amended in its Argument on pages 5 to 9; and

E. By Commission Order G-96-08 dated June 17, 2008 (Exhibit A-1), the Commission established a Procedural Conference for September 9, 2008 to hear submissions on the principal issues arising from or related to the Application, and the procedure for the review of the Application; and

F. Following the Procedural Conference the Commission issued Order G-126-08 dated September 11, 2008 (Exhibit A-4) and ordered, among other things, that the evidentiary phase for the Mica Units 5 and 6 Definition phase expenditures request would close on October 15, 2008 and final argument on those expenditures would form part of the Arguments following the close of the evidentiary phase of the Oral Hearing, which was at that time scheduled to commence on January 8, 2009; and

G. A Second Procedural Conference was established as a result of an amendment to the Hearing schedule proposed in BC Hydro's letter to the Commission dated November 14, 2008 (Exhibit B-5). In a follow-up letter from BC Hydro dated November 19, 2008 (Exhibit B-6), it requested that the Commission issue early orders with respect to the Mica Units 5 and 6 Definition phase expenditure request and with respect to the Fort Nelson Generating Station Upgrade Project ("FNGU") Definition and Implementation phase expenditures request; and

H. At the Second Procedural Conference on November 28, 2008, all Parties spoke to, among other things, the possibility of moving the FNGU to a separate hearing, a separate Argument phase for Mica Units 5 and 6 and separate orders and decisions for those two matters; and

I. Commission Order G-178-08 dated November 28, 2008 (Exhibit A-12) amended the regulatory timetable and established that the Oral Hearing would commence on February 19, 2009. The Order also established that the Mica Units 5 and 6 Definition phase expenditure request would be dealt with as part of the main 2008 LTAP argument phase and the FNGU Definition and Implementation phase expenditures request would remain part of the 2008 LTAP evidentiary and argument phases; and

J. The Oral Hearing commenced on February 19, 2009 and ended on March 12, 2009. BC Hydro filed its Argument on April 9, 2009; Intervenors filed their Arguments on April 27, 2009; and BC Hydro filed its Reply on May 13, 2009; and

K. By letter dated May 25, 2009 (Exhibit A-20), the Commission notified all Parties that the Oral Phase of Argument was required. All Parties were asked to advise the Commission if they would be prepared to make submissions on a list of matters outlined in that letter. The Oral Phase of Argument took place on June 1, 2009; and

L. By Commission Order G-69-09 dated June 8, 2009, the Commission determined that the $30 million expenditure in F2009 to F2011 to undertake and complete the Definition phase work for Mica Units 5 and 6 was in the public interest. By Commission Order G-75-09 dated June 15, 2009 the Commission determined that the $140.1 million expenditure requested to complete the Definition phase and Implementation phase of the Fort Nelson Generating Station Upgrade Project Case 3.2 ("FNGU3") was in the public interest; and

M. The Commission Panel has considered the balance of the Application, the evidence, and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to subsection 44.1(6) of the Act, the 2008 LTAP is not in the public interest and is rejected.

2. Pursuant to subsection 44.2(3) of the Act, the following expenditures are in the public interest and are accepted:

   - $418.0 million in F2009, F2010 and F2011 for the Implementation of Demand-Side Management ("DSM") Plans generally as described in BC Hydro's Adjusted Option A;
   - $600,000 in F2009 and F2010 to undertake and complete the Definition phase work for capacity-related DSM;
   - $1.6 million in F2010 for sustaining capital to ensure the reliability of Burrard;
   - $41.0 million in F2009 and F2010 to undertake and complete the Site C Stage 2 Definition and Consultation phase work.

3. Pursuant to subsection 44.2(3) of the Act, the following expenditure is not in the public interest and is rejected:

   - $2.0 million in F2009 and F2010 to complete the Definition phase work, and to implement the Clean Power Call.

4. The Contingency Resource Plans are approved for inclusion in BC Hydro's Network Integrated Transmission Services update to British Columbia Transmission Corporation pursuant to Commission Directive 3 in Order G-58-05.

5. The following endorsements are made:

   - The Clean Power Call ("CPC") eligibility requirement;
   - The DSM amortization period to remain at 10 years;
   - The filing of DSM performance reports on an annual basis going forward, subject to a transition measure;
   - The elimination of F05/F06 RRA Decision Directives 62 and 64 which relate to Load Displacement projects being considered as supply side alternatives;

- The amendment of F05/F06 RRA Decision Directive 60 to read as follows: "seek approval for all new Power Smart programs with a Total Resource Cost benefit/cost ratio of less than 1.0"; and
- BC Hydro's plan to rely on Burrard for planning purposes for 900 MW of capacity.

6. The following endorsements are declined:

- The CPC pre-attrition and post-attrition targets of 3,000 GWh/year and 2,100 GWh/year respectively;
- BC Hydro's plan to reduce its reliance for planning purposes on Burrard to 3,000 GWh/year of firm energy; and
- The continuation of BC Hydro's capital plan review process as proposed in its F2009/F2010 Revenue Requirement Application.

7. BC Hydro will comply with all other directives in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 27th day of July 2009.

BY ORDER

Original signed by:

Anthony J. Pullman
Panel Chair/Commissioner

EXCERPTS FROM STATUTES AND REGULATIONS

For convenience, the following sections of the *Act*, SD 10 and M271 are reproduced below:

- the *Utilities Commission Act*- sections 1 (in part) and 44.1, 44.2, 64.01, 64.02 and 64.04;
- SD 10- sections 1 (in part) and 3; and
- M271- sections 1 (in part), 3 and 4.

Utilities Commission Act

Section 1 of the *Act* contains the following relevant definitions:

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;

"government's energy objectives" means the following objectives of the government

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation;

Section 44.1 of the *Act* sets out the responsibilities of public utilities and the jurisdiction of the Commission in respect of long-term resource plans.

44.1 (1) In this section, **"demand increase"** means the greater of

(a) the difference between

(i) the sum of the estimate referred to in subsection (4) (b) and a prescribed amount, if any, and

(ii) the demand the authority would serve during the period referred to in subsection (4) (b) if the demand in each year of that period remains equal to the demand referred to in subsection (4) (a), and

(b) zero.

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) A long-term resource plan filed under subsection (2) by the authority before the end of the 2020 calendar year must include, in addition to everything referred to in subsection (2) (a) to (g), all of the following:

> (a) a statement of the demand for electricity the authority served in the year beginning on April 1, 2007, and ending on March 31, 2008;
>
> (b) an estimate of the total demand for electricity the authority would expect to serve in the period beginning on April 1, 2008, and ending on March 31, 2021, if no new demand-side measures are taken during that period;
>
> (c) a statement of the demand-side measures the authority would need to take so that, in combination with demand-side measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50% by 2020.

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

> (a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or
>
> (b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

> (a) the public utility may resubmit the part within a time specified by the commission, and
>
> (b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

> (a) the government's energy objectives,
>
> (b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable,

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

Section 44.2 addresses expenditure schedules:

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the

commission, subject to subsections (5) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Sections 64.01, 64.02 and 64.04 address aspects of electricity self-sufficiency, clean and renewable resources, and smart meters.

64.01 (1) The authority must

(a) by the 2016 calendar year, achieve electricity self-sufficiency according to the prescribed criteria, and

(b) maintain, according to the prescribed criteria, electricity self-sufficiency in each calendar year after achieving it.

(2) A public utility, in planning for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year.

64.02 (1) To facilitate the achievement of the government's goal that at least 90% of the electricity generated in British Columbia be generated from clean or renewable resources, a person to whom this section applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) This section applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

64.04 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that

application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters.

SD 10

Section 3 of SD 10 reads as follows:

Subject to section 5 (2) (a), in regulating, and fixing rates for, the authority, including, without limitation,

(a) considering an application made by the authority for a certificate of public convenience and necessity under section 45 of the Act,

(b) doing anything referred to in section 45 (6.2) (a), (b) or (c) of the Act with respect to a plan filed by the authority under section 45 (6.1) of the Act, and

(c) considering an energy supply contract under section 71 of the Act,

the commission must use the criterion that the authority is to achieve energy and capacity self-sufficiency by becoming capable of

(a) meeting, by 2016 and each year thereafter, the electricity supply obligations, and

(b) exceeding, as soon as practicable but no later than 2026, the electricity supply obligations by at least 3000 gigawatt hours per year and by the capacity required to integrate that energy in the most cost-effective manner

solely from electricity generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities.

Subsection 1 (1) of SD 10 includes the following definitions:

"critical water conditions" means the most adverse sequence of stream flows occurring within the historical record.

"electricity supply obligations" means:

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the Act, and

(b) any other electricity supply obligations that exist at the time this Special Direction comes into force

determined by using the authority's mid-level forecasts of its energy requirements and peak load, taking into account demand-side management initiatives, that are accepted by the commission from time to time.

''firm energy capability" means the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions.

Subsection 1 (2) of SD 10 further defines firm energy capability by stating:

The definition of "firm energy capability" in subsection (1) must be interpreted for the purposes of this Special Direction so as to be consistent with the fact that, in 2006, the authority's firm energy capability was 42 600 gigawatt hours.

<u>M271</u>

Section 1 of M271 contains the following relevant definitions:

"plan portfolio" means the class of demand-side measures that is composed of all the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the *Act.*

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

Section 3 of M 271 reads as follows:

A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Section 4 reads as follows:

(1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program," the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission may include in the benefit a proportion of the benefit that, in the commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

ILLUSTRATIVE MODEL

In this Appendix, the Commission Panel provides, for illustrative purposes only, a model for summarizing the presentation of the principal parameters of a LTAP.

In order to provide context by way of quantifiable results, certain assumptions have been made, which are generally consistent with the materials presented by the parties and/or the findings and suggestions offered by the Commission Panel in this Decision. These include:

- the progressive introduction of the "insurance requirement" over the period 2008 to 2026 at an increment of 167 GWh/year;
- the inclusion of the market allowance of 2,500 GWh/year up to Dec. 31 2016;
- a DSM Adjustment to incorporate the projection of DSM savings for the entire planning period at the average level of Option A provided by BC Hydro for the "active" period identified from Exhibit C23-9, rounded as 900 GWh/year; and
- the reliance on Burrard for planning purposes as capable of 5,000 GWh/year.

The following table summarizes the results for "milestone" years of F2012, 2017, F2022, and F2027, and identifies the residual "gaps" for planning purposes in those years. A complete spread sheet for the planning period is attached to this Appendix.

Fiscal Year	**F2012**	**F2017**	**F2022**	**F2027**
Load Forecast	61,362	66,172	69,318	73,847
DSM (Option A)	3,000	7,632	10,158	11,616
DSM Adjustment	0	-132	1842	4,844
Total DSM	3,000	7,500	12,000	16,500
Electricity Supply Obligation	58,362	58,672	57,318	57,347
Insurance	667	1,500	2,333	3,000
Adjusted ESO	**59,029**	**60,172**	**59,651**	**60,347**
Existing and Committed Resources	55,406	55,608	54,786	54,748
Burrard Adjustment	2,000	2,000	2,000	2,000
Market Allowance	2,500			
Bioenergy Ph. 1	498	426	63	0
Total	60,404	58,034	56,849	56,748
Gap	**(1,375)**	**2,138**	**2,802**	**3,599**

The Commission Panel suggests that summary presentations, on the bases of "before" and "after" LTAP initiatives, in a format similar to that presented above could be helpful to the Commission and Intervenors in reviewing BC Hydro's next LTAP application.

BC HYDRO
LOAD/RESOURCE BALANCE

Attachment to Appendix 2

FISCAL YEAR		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LOAD FORECAST		61362	62516	64470	65325	65281	66172	66898	67614	68209	68480	69318	70166	71118	72080	72921	73847	74841
DSM (OPTION A)		3000	3713	4663	5591	6664	7632	8270	9056	9551	9923	10158	10358	10847	11085	11487	11616	11917
DSM ADJUSTMENT			187	137	109	-64	-132	130	244	649	1177	1842	2542	2953	3615	4113	4884	5483
TOTAL DSM	900	3000	3900	4800	5700	6600	7500	8400	9300	10200	11100	12000	12900	13800	14700	15600	16500	17400
ELECTRICITY SUPPLY OBLIGATIONS		58362	58616	59670	59625	58681	58672	58498	58314	58009	57380	57318	57266	57318	57380	57321	57347	57441
INSURANCE	167	667	833	1000	1167	1333	1500	1667	1833	2000	2167	2333	2500	2667	2833	3000	3000	3000
ADJUSTED ELECTRICITY SUPPLY OBLIGATIONS		59029	59449	60670	60792	60014	60172	60165	60147	60009	59547	59651	59766	59985	60213	60321	60347	60441
EXISTING & COMMITTED RESOURCES		55406	55625	55565	55632	55672	55608	55378	54833	54833	54833	54786	54748	54748	54748	54748	54748	54748
BURRARD ADJUSTMENT		2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
BIO ENERGY PH I		498	521	521	521	521	426	277	277	277	80	63	63	63	63	11		
TOTAL		57904	58146	58086	58153	58193	58034	57655	57110	57110	56913	56849	56811	56811	56811	56759	56748	56748
GAP		1125	1303	2584	2639	1821	2138	2510	3037	2899	2634	2802	2955	3174	3402	3562	3599	3693

ACRONYMS AND ABBREVIATIONS

2007 Energy Plan	The BC Energy Plan: A Vision for Clean Energy
2008 LTAP	2008 Long Term Acquisition Plan
5L83	The Proposed 500 kV Transmission Line between BC Hydro's Nicola and Meridian Substations
AMEC	AMEC Americas Limited
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, Council of Senior Citizens' Organization of BC, End Legislated Poverty and federated anti-poverty groups of BC and Tenant Resource and Advisory Centre
BCSEA	BC Sustainable Energy Association & Sierra Club of Canada BC Chapter
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
BRP	Base Resource Plan
Burrard	Burrard Thermal Generating Station
CAC	Common Airborne Contaminants
CAT	Climate Action Team
CCGT	Combined-Cycle Gas Turbine
CE	Canadian Entitlement
CEC	Commercial Energy Consumers of BC
COD	Commercial Operations Date
COPE	Canadian Office and Professional Employees Local Union 378
CPC	Clean Power Call
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review
CRP	Contingency Resource Plan
CWS	Canada-wide Standard
DEI	Distribution Efficiency Initiative
DSM	Demand Side Management
E&C	Existing and Committed

ECE	Energy Conservation and Efficiency
EE	Energy Efficiency
EEC	Energy Efficiency and Conservation Application
ELA	Electric Load Avoidance
EMA	*Environmental Management Act*
EPA	Energy Purchase Agreement, the expression used by BC Hydro to refer to an Energy Supply Contract
EPV	Electric Plug-In Vehicle
ESVI	Energy Solutions for Vancouver Island Society, Okanagan Environmental Industry Alliance, IslandTransformations.org and Rental Owners and Managers Society of BC
FELCC	Firm Electric Load Carrying Capability
FNGU	Fort Nelson Generating Station Upgrade Project
FNU2	Fort Nelson Gas Generating Unit Project #2
FNU3	Fort Nelson Gas Generating Unit Project #3
GWh	Gigawatt hour
IEP	Integrated Electricity Plan
ILM	Interior to Lower Mainland
IPPBC	Independent Power Producers' Association of British Columbia
IR	Information Request
ISD	In-Service Date
IT	Information Technology
JIESC	Joint Industry Electricity Steering Committee
LD	Load Displacement
LFV	Lower Fraser Valley
LM/VI	Lower Mainland/Vancouver Island
MEMPR	BC Minister of Energy Mines and Petroleum Resources
Mica 5/6	Mica Units 5 and 6
MOE	BC Ministry of Environment
MTP	Major Threshold Project
NIA	Non-Integrated Areas
NSA	Negotiated Settlement Agreement
OED	Oxford English Dictionary

PV	Present Value
PVEA	Peace Valley Environmental Association
RDA	Rate Design Application
REC	Renewable Energy Credit
RIB	Residential Inclining Block
RIM	Ratepayers Impact Measurement
RMR	Reliability Must Run
ROU	Resource Options Update
RRA	Revenue Requirements Application
RWDI	RWDI AIR Inc.
SCGT	Simple-Cycle Gas Turbine
SD	Special Direction
SMI	Smart Meter Initiative
SOP	Standing Offer Program
TAN	Texada Action Now Community Association
Terasen	Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
The Act	*Utilities Commission Act*
The Commission	British Columbia Utilities Commission
TRC	Total Resource Cost
UEC	Unit Energy Cost
Vanport	Vanport Sterilizers Inc.
VIGP	Vancouver Island Gas Project
VO	Voltage Optimization
VVO	Volt Var Optimization
WCI	Western Climate Change

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro and Power Authority
2008 Long Term Acquisition Plan

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated June 17, 2008 issuing Commission Order No. G-96-08 and Notice of Application and Procedural Conference attached as Appendix B to the Order
A-2	Letter dated July 10, 2008 issuing Information Request No. 1 to BC Hydro
A-3	Letter dated September 4, 2008 issuing an Agenda for the Procedural Conference
A-4	Letter dated September 11, 2008 issuing Order G-126-08 with Regulatory Timetable for the application
A-5	Letter dated September 11, 2008 issuing Information Request No. 2 to BC Hydro
A-6	Letter dated November 17, 2008 issuing Notice of Second Procedural Conference
A-7	Letter dated November 21, 2008 issuing Information Request No. 1 to Texada Action Now Community Association (TANCA)
A-8	Letter dated November 21, 2008 issuing Information Request No. 1 to COPE 378
A-9	Letter dated November 21, 2008 issuing Information Request No. 1 to Vanport Sterilizers Inc.
A-10	Letter dated November 21, 2008 issuing Information Request No. 1 to BC Sustainable Energy Association and Sierra Club of BC (BCSEA/SCBC)
A-11	Letter dated November 28, 2008 issuing Order L-56-08 for a deadline extension to the Intervenor Evidence
A-12	Letter dated November 28, 2008 issuing Order G-178-08 amending the Regulatory Timetable
A-13	Letter dated December 8, 2008 issuing Information Request No. 1 to Independent Power Producers Association of BC (IPPBC)

Exhibit No.	Description
A-14	Letter dated December 11, 2008 requesting the Applicant and Intervenors to comment on ESVI's application for leave to represent three additional entities: the Okanagan Environmental Industry Alliance ("OEIA"), Island Transformation.org ("ITO"), and Rental Owners and Managers Society of BC ("ROMSBC")
A-15	Letter dated January 9, 2009 issuing Panel Information Request No. 1 to BC Hydro
A-16	Letter dated January 12, 2009 issuing Commission Information Request No. 3 to BC Hydro
A-17	Letter dated February 12, 2009 issuing Procedural Information to Participants
A-18	Letter dated May 11, 2009 Requesting comments on extending the filing dates for Oral Argument
A-19	Letter dated May 13, 2009 filing schedule for Oral Hearing
A-20	Letter dated May 25, 2009 Oral Phase of Argument Agenda
A-21	Letter dated April 2, 2009 to Participants providing a list of issues for consideration on which the Commission Panel requests Intervenors comment on when preparing their submissions in argument

COMMISSION COUNSEL DOCUMENTS

A2-1	**Submitted at Hearing** February 23, 2009 Letter dated November 21, 2008 BCTC TSCP F2010 and F2011
A2-2	**Submitted at Hearing** February 23, 2009 Letter dated October 29, 2008 Public utilities commission Proposed decision of ALI Simon
A2-3	**Submitted at Hearing** February 26, 2009 BC Hydro Undertaking No.10
A2-4	**Submitted at Hearing** March 03, 2009 Western Climate Initiative paper
A2-5	**Submitted at Hearing** March 06, 2009 Letter dated July 15, 2008 Informing BCUC that the Ministry of Energy, Mines and Petroleum Resources is currently working with British Columbia utility representatives to devise a common protocol for reporting on energy conservation, energy efficiency and demand side management programs.
A2-6	**Submitted at Hearing** March 06, 2009 Excerpt from BC Hydro Revenue Requirement Hearing May-31-2004 Volume 13
A2-7	**Submitted at Hearing** March 06, 2009 Reference to BCHydro 2006 IEP-LTAP Exhibit
A2-8	**Submitted at Hearing** March 06, 2009 Ministry of Energy, Mines and Petroleum News Release December 1, 2008

Exhibit No.	Description
A2-9	**Submitted at Hearing** March 06, 2009 BC Hydro Revenue Requirement Hearing June 1,2004 Volume 14
A2-10	**Submitted at Hearing** March 06, 2009 BC Hydro Revenue Requirement F2009, F2010 Volume 5 Proceedings October 8, 2008

APPLICANT DOCUMENTS

B-1	Letter dated June 12, 2008 filing the 2008 Long Term Acquisition Plan (Volume 1 of 3)
B-1-1	Appendices A through R to the 2008 Long Term Acquisition Plan (Volumes 2 and 3 of 3)
B-1-2	**CONFIDENTIAL** – Letter dated June 12, 2008 filing confidential information under section 3.3.10.2 – Results
B-1-3	Letter dated June 20, 2008 filing of potential Information Request topics
B-1-4	Letter dated July 4, 2008 filing an Addendum to the Long Term Acquisition Plan
B-1-5	Letter dated July 4, 2008 filing Errata to the Long Term Acquisition Plan
B-1-6	Letter dated August 19, 2008 filing Errata to Chapters 1 and 6 of the Long Term Acquisition Plan Application and amended Appendix A
B-1-7	Letter received August 25, 2008 filing Evidentiary Update to Appendix N2 – Fort Nelson Generating Station Upgrade
B-1-8	Letter dated September 5, 2008 filing Errata #2 to the application
B-1-9	Letter dated October 10, 2008 filing Errata to the Application
B-1-10	Letter dated October 24, 2008 filing Fort Nelson Evidentiary Update
B-1-11	Letter dated December 23, 2008 filing Errata to Evidentiary Update (Exhibit B-1-10)
B-1-12	Order in Council 74-2009 inserted as page 6A into Exhibit B-1-1, Appendix B-4, page 6A of 13
B-1-13	**Submitted at Hearing** February 27, 2009 BC Hydro Resource Options Document from 2008 LTAP Application
B-2	Letter dated July 31, 2008 filing confirmation of publication of the Notice of Application & Procedural Conference

Exhibit No.	**Description**
B-3	Letter dated August 21, 2008 filing responses to Information Request No. 1 from the Commission and Intervenors
B-3-1	**CONFIDENTIAL** – Letter dated August 21, 2008 filing responses to Commission Information Request No. 1
B-3-2	Letter dated August 21,2008 filing responses to Information Requests Submitted in the BC Hydro F2009/F2010 Revenue Requirement Application proceeding and addressed in the BC Hydro 2008 LTAP proceeding
B-3-3	Letter dated September 5, 2008 filing the revised responses to the JIESC Information Requests No. 1.4.1 and 1.17.1
B-3-4	Letter dated October 10, 2008 filing of Revised Responses to Commission Information Requests No. 1.43.2 and 1.57.1
B-3-5	Letter dated October 30, 2008 filing revised responses to Commission 1.115.2 and BCSEA 1.20.3
B-3-6	Letter dated February 3, 2009 filing revised response to Commission Information Request 1.150.1
B-3-7	**Submitted at Hearing** February 27, 2009 Spreadsheet of Table 3-21 of Exhibit 8-1 including dependable capacity
B-4	Letter dated October 15, 2008 filing of Information Responses #2 to the Commission and Intervenors
B-4-1	CONFIDENTIAL - Letter dated October 15, 2008 filing Information Responses #2.177.3 to the Commission and Intervenors
B-4-2	Letter dated October 24, 2008 issuing responses to Fort Nelson Information Request Second Round
B-4-3	Letter dated October 30, 2008 filing revised responses to BCUC 2.174.1, BCUC 2.199.3 and JIESC 2.23.3
B-4-4	Letter dated November 14, 2008 filing Revised Response to COPE Information Request 2.9.4
B-5	Letter dated November 14, 2008 filing response to IPPBC letter dated November 14, 2008 (Exhibit C17-4)
B-6	Letter dated November 19, 2008 filing comments and recommendations on the Regulatory Timetable

Exhibit No.	Description
B-7	Letter dated November 21, 2008 filing Information Request No. 1 to COPE 378
B-8	Letter dated November 21, 2008 filing Information Request No. 1 to BC Sustainable Energy Association and Sierra Club of Canada BC Chapter (BCSEA/SCCBC)
B-9	Letter dated December 8, 2008 issuing Information Request No. 1 to Independent Power Producers Association of BC (IPPBC)
B-10	Letter dated December 22, 2008 filing Evidentiary Update
B-11	Letter dated January 12, 2009 filing further information regarding Clean Power Call volume
B-12	Letter dated February 10, 2009 _BC Hydro IR Responses NOTE: updated replacement of pdf from BCH
B-12-1	CONFIDENTIAL- Letter dated February 10, 2009 _BC Hydro IR Responses
B-13	Letter dated February 13, 2009 BC Hydro Direct Testimony
B-13-1	Letter dated February 16, 2009 Four BC Hydro Direct Testimony Panels
B-13-2	**Submitted at Hearing** February 24, 2009 Information Requests sorted by Topic
B-14	Letter dated February 17, 2009 BC Hydro Opening Statement
B-15	Letter dated February 18, 2009 BC Hydro Bioenergy Call Phase I Request for Proposals Report
B-16	**Submitted at Hearing** February 24, 2009 BC Hydro Service Plan
B-17	**Submitted at Hearing** February 24, 2009 BC Hydro Shareholder’s Letter of Expectations
B-18	**Submitted at Hearing** February 24, 2009 **Real GDP Growth Chart**
B-19	**Submitted at Hearing** February 25, 2009 BCHydro Undertaking No-5 Transcript Reference
B-20	**Submitted at Hearing** February 25, 2009 BCHydro Undertaking No-7 Transcript Reference
B-21	**Submitted at Hearing** February 25, 2009 BCHydro Undertaking No-8 Transcript Reference
B-22	**Submitted at Hearing** February 25, 2009 BCHydro Undertaking No-9 Transcript Reference
B-23	**Submitted at Hearing** February 27, 2009 BCHydro Undertaking No-4 Transcript Reference
B-24	**Submitted at Hearing** February 27, 2009 BCHydro Undertaking No-12 Transcript Reference
B-25	**Submitted at Hearing** February 27, 2009 BCHydro Undertaking No-21 Transcript Reference

Exhibit No.	Description
B-26	**Submitted at Hearing** February 27, 2009 BCHydro Undertaking No-22 Transcript Reference
B-27	**Submitted at Hearing** February 27, 2009 Mr Godsoe Transcript excerpts
B-28	**Submitted at Hearing** March 02, 2009 BCHydro Undertaking No-3 Transcript Reference
B-29	**Submitted at Hearing** March 02, 2009 BCHydro Undertaking No-27 Transcript Reference
B-30	**Submitted at Hearing** March 02, 2009 BCHydro Undertaking No-28 Transcript Reference
B-31	**Submitted at Hearing** March 02, 2009 BCHydro Undertaking No-29 Transcript Reference
B-32	**Submitted at Hearing** March 02, 2009 BCHydro Undertaking No-32 Transcript Reference
B-33	**Submitted at Hearing** March 03, 2009 BCHydro Undertaking No-25 Transcript Reference
B-34	**Submitted at Hearing** March 03, 2009 BCHydro Undertaking No-45 Transcript Reference
B-35	**Submitted at Hearing** March 04, 2009 NTREE Technology Roadmap
B-36	**Submitted at Hearing** March 04, 2009 Comments on the Climate Action Team Report
B-37	**Submitted at Hearing** March 04, 2009 BCSustainable Energy Budget Submission 2009
B-38	**Submitted at Hearing** March 05, 2009 BCHydro Undertaking No-1 Transcript Reference
B-39	**Submitted at Hearing** March 05, 2009 BCHydro Undertaking No-2 Transcript Reference
B-40	**Submitted at Hearing** March 05, 2009 BCHydro Undertaking No-14 Transcript Reference
B-41	**Submitted at Hearing** March 05, 2009 BCHydro Undertaking No-42 Transcript Reference
B-41-A	Outstanding Undertaking No. 42 filed March 13, 2009
B-42	**Submitted at Hearing** March 06, 2009 BC Hydro 2008 LTAP Hearing UNDERTAKING NO. 11 (PUBLIC VERSION)
B-43	**Submitted at Hearing** March 06, 2009 BC Hydro Wind Integration Project Wind Data Study Results
B-44	**Submitted at Hearing** March 06, 2009 BC Hydro 2008 LTAP Hearing UNDERTAKING NO. 53
B-45	Outstanding Undertaking No. 37 filed March 13, 2009
B-46	Outstanding Undertaking No. 40 filed March 13, 2009
B-47	Outstanding Undertaking No. 46 filed March 13, 2009

Exhibit No.	Description
B-48	Outstanding Undertaking No. 48 filed March 13, 2009
B-49	Outstanding Undertaking No. 56 filed March 13, 2009
B-50	Outstanding Undertaking No. 58 filed March 13, 2009
B-51	Outstanding Undertaking No. 52 filed March 13, 2009
B-52	Outstanding Undertaking No. 13 filed March 19, 2009
B-53	Outstanding Undertaking No. 15 filed March 19, 2009
B-54	Outstanding Undertaking No. 18 filed March 19, 2009
B-55	Outstanding Undertaking No. 20 filed March 19, 2009
B-56	Outstanding Undertaking No. 23 filed March 19, 2009
B-57	Outstanding Undertaking No. 49 filed March 19, 2009
B-58	Outstanding Undertaking No. 54 filed March 19, 2009
B-59	Outstanding Undertaking No. 55 filed March 19, 2009
B-60	Outstanding Undertaking No. 60 filed March 19, 2009
B-61	Outstanding Undertaking No. 60 filed March 19, 2009
B-62	Outstanding Undertaking No. 61 filed March 19, 2009
B-63	Outstanding Undertaking No. 62 filed March 19, 2009
B-64	Outstanding Undertaking No. 68 filed March 19, 2009
B-65	Outstanding Undertaking No. 70 filed March 19, 2009
B-66	Outstanding Undertaking No. 71 filed March 19, 2009
B-67	Undertaking No. 17 March 26, 2009
B-68	Undertaking No. 26 March 26, 2009
B-69	Undertaking No. 44March 26, 2009
B-70	Undertaking No. 65 March 26, 2009
B-71	Undertaking No. 67 March 26, 2009

Exhibit No.	Description
B-72	Undertaking No. 69 March 26, 2009
B-73	Undertaking No. 10 March 26, 2009
B-74	Undertaking No. 47 March 26, 2009
B-75	Undertaking No. 50 March 26, 2009
B-76	Undertaking No. 51 March 26, 2009
B-77	Undertaking No. 66 March 26, 2009
B-78	Undertaking No. 19 filed March 27, 2009
B-79	Undertaking No. 63 filed March 27, 2009
B-80	Undertaking No. 16 filed March 27, 2009
B-81	Undertaking No. 34 filed March 27, 2009
B-82	Undertaking No. 35 filed March 27, 2009
B-83	Undertaking No. 36 filed March 27, 2009
B-84	Undertaking No. 33 filed March 27, 2009
B-85	Undertaking No. 57 filed March 27, 2009
B-86	Undertaking No. 64 filed March 27, 2009
B-87	Undertaking No. 30 filed March 27, 2009
B-88	Undertaking No. 72 filed March 27, 2009
B-89	Undertaking No. 39 filed March 27, 2009

INTERVENOR DOCUMENTS

C1-1	**EPCOR UTILITIES INC. (EPCOR) –** Letter dated June 13, 2008, from Kelly Lail, Director, filing request for Registered Intervenor status

Exhibit No.	Description
C2-1	**WESTPAC LNG CORPORATION –** Letter dated June 18, 2008, from Robert Green, Vice President, filing request for Registered Intervenor status
C2-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro
C3-1	**FRED OLSEN RENEWABLES (CANADA) LTD. –** Online web registration received June 18, 2008, from David Kusnierczyk, filing request for Registered Intervenor status
C3-2	Information Request No. 1 dated July 11, 2008
C3-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C4-1	**PLUTONIC POWER CORPORATION (PPC) –** Letter dated June 19, 2008, from Rupert Legge, Senior Vice President, filing request for non-active status
C4-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro
C5-1	**VANPORT STERILIZERS INC.** – Letter dated June 19, 2008 from Richard Tennant requesting Intervenor status and comments on Appendix F4a to the BC Hydro 2008 Long-Term Acquisition Plan
C5-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C5-3	Letter dated November 14, 2008 filing Evidence
C5-4	Email dated December 8, 2008 filing Information Request to IPPBC evidence
C5-5	Letter dated December 18, 2008 filing clarification of written evidence submitted in Exhibit C5-3
C5-6	Letter dated January 12, 2009 filing Information Request to BC Hydro
C6-1	**THE BC OLD AGE PENSIONERS ORGANIZATION *ET AL*. (BCOAPO)** – Letter dated June 20, 2008 requesting Intervenor status
C6-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C6-3	Letter dated September 10, 2008 filing Information Request No. 2 to BC Hydro
C6-4	Letter dated December 8, 2008 issuing Information Request No. 1 to Independent Power Producers Association of BC (IPPBC)

Exhibit No.	Description
C6-5	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C6-6	Letter dated February 17, 2009 requesting that BC Hydro be asked to file the publicly-available contents of its Application seeking approval of the four Electricity Purchase Agreements arising from the Bioenergy Call
C7-1	**BRITISH COLUMBIA TRANSMISSION CORPORATION (BCTC)** – Letter dated June 20, 2008 requesting Intervenor status
C8-1	**GOLDEN AREA COMMUNITY ECONOMIC DEVELOPMENT SOCIETY (GACEDS) –** Online web registration received June 23, 2008, from Robert E. Miller, filing request for Registered Intervenor status
C9-1	**ENMAX CORPORATION –** Online web registration received June 23, 2008, from Ron Sanderson, filing request for Registered Intervenor status
C10-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CECBC)** – Letter dated June 25, 2008 from Christopher P. Weafer, Owen Bird, legal counsel, filing request for Registered Intervenor status
C10-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro
C10-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C10-4	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C10-5	**Submitted at Hearing** February 20, 2009 BCH Conservation Potential Review
C11-1	**COLUMBIA POWER CORPORATION (CPC)** – Letter dated June 25, 2008 from Fred J. Weisberg, Weisberg Law Corporation, legal counsel, filing request for Registered Intervenor status
C12-1	**PEACE VALLEY ENVIRONMENTAL ASSOCIATION (PVEA)** – Email dated June 26, 2008, from Richard Gathercole, filing request for Registered Intervenor status
C12-2	Letter dated July 16, 2008 filing Information Request No. 1 to BC Hydro
C12-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro

Exhibit No.	Description
C12-4	**Submitted at Hearing** February 23, 2009 Letter dated January 26, 2009 from K&A Boon to B. Elton BC Hydro re BCH Site C
C13-1	**TERASEN GAS INC. (TGI)** – Letter dated June 30, 2008, from Tom Loski, Chief Regulatory Officer, filing request for Registered Intervenor status
C13-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C13-3	Letter dated September 11, 2008, filing Information Request No. 2 to BC Hydro
C13-4	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C13-5	LETTER DATED FEBRUARY 19, 2009 **TGI** DOCUMENTS FOR CROSS EXAMINATION OF PANEL
C13-6	Document received February 19, 2009 Province of British Columbia Strategic Plan
C13-7	**Submitted at Hearing** February 24, Materials Referred to in Cross-examination of Panel 2
C13-8	**Submitted at Hearing** February 24, Terasen Witness Aid for Panel 2
C13-9	**Submitted at Hearing** February 27, 2009 Materials Referred to in Cross-Examination of Panel 3
C13-10	**Submitted at Hearing** February 27, 2009 Avista Construction Incentive Brochure
C13-11	**Submitted at Hearing** March 03, 2009 Witness_Aid_Fuel_Cost_Comparison
C13-12	**Submitted at Hearing** March 03, 2009 External Review Panel Consultative Report on the BC Hydro 2007 Conservation Potential Review
C14-1	**EARTHFIRST CANADA INC. –** Online web registration received July 1, 2008, from Ron Percival, filing request for Registered Intervenor status
C15-1	**ENCANA CORPORATION –** Online web registration received July 2, 2008, from Rinde K. Powell, filing request for Registered Intervenor status
C15-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro

Exhibit No.	Description
C16-1	**COPE 378 –** Online web registration received July 2, 2008, from Lori Winstanley, filing request for Registered Intervenor status
C16-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro
C16-3	Letter dated September 10, 2008 filing notice of new contact information
C16-4	Letter dated September 10, 2008 filing withdrawal of new contact information
C16-5	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C16-6	Letter dated November 14, 2008 filing Direct Evidence of Dr. Marvin Shaffer
C16-7	Letter dated December 18, 2008 filing responses to BC Hydro Information Request No. 1
C16-8	Letter dated December 18, 2008 filing responses to BCSEA et al Information Request No. 1
C16-9	Letter dated December 18, 2008 filing responses to Commission Information Request No. 1
C16-10	Letter dated January 12, 2009 issuing Information Request No. 3 to BC Hydro
C16-11	**Submitted at Hearing** February 25, BC Hydro Thermal Generation System
C16-12	Letter dated March 16, 2009 Undertaking_Transcript_Reference15_2819-2820_ESVI
C17-1	**INDEPENDENT POWER PRODUCERS ASSOCIATION OF BC (IPPBC) –** Letter dated July 2, 2008, from David Austin, Tupper Jonsson & Yeadon, legal counsel, filing request for Registered Intervenor status on behalf of Steve Davis, President
C17-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C17-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C17-4	Letter dated November 14, 2008 filing response to BC Hydro's proposed Hearing Schedule Change
C17-5	Letter received December 1, 2008 filing Evidence from Chris Ball, M. Jaccard and S. Landry
C17-6	Letter dated January 6, 2009 filing responses to Information Requests and Revised Excel Spreadsheet with respect to evidence of Chris Ball and final report of JC Nyboer
C17-7	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C17-8	Letter dated January 16, 2009 Speech from the Throne

Exhibit No.	Description
C17-9	**Submitted at Hearing** – Excerpt from Transcript Volume 8 (page 983) from the BC Hydro Review of the F2007 and F2008 Revenue Requirements Application and Review of the 2006 Integrated Electricity Plan and the Approval of the 2006 Long-Term Acquisition Plan
C17-10	**Submitted at Hearing** – Excerpt from Transcript Volume 3 from the BC Hydro Review of the F2009 and F2010 Revenue Requirements Application
C17-11	**Submitted at Hearing** – Excerpt from Transcript Volume 7 (pages 634-635) from the BC Hydro Review of the F2007 and F2008 Revenue Requirements Application and Review of the 2006 Integrated Electricity Plan and the Approval of the 2006 Long-Term Acquisition Plan
C17-12	**Submitted at Hearing-** IPPBC Excerpt commenting on slide 13
C17-13	**Submitted at Hearing** February 24, BC Hydro GM Shrum Generator 3 Runner Failure
C17-14	**Submitted at Hearing** February 24, BC Hydro Undertaking Transcript Reference
C17-15	**Submitted at Hearing** February 24, Electric Car Press Release
C17-16	**Submitted at Hearing** February 25, Excerpt from Jubak's Journal MSN Money
C17-17	**Submitted at Hearing** February 27, BC Hydro Undertaking No. 35
C17-18	**Submitted at Hearing** February 27, F2009 and F2010 Revenue Transcript12
C17-19	**Submitted at Hearing** February 27, Western Climate Initiative plan
C17-20	**Submitted at Hearing** February 27, BC Hydro's 1995 Integrated Electricity Plan
C17-21	**Submitted at Hearing** February 27, APPENDIX C. INTENSITY OF CUSTOMER DEMAND RESPONSE
C17-22	**Submitted at Hearing** February 27, BC Hydro's Annual Report 1980/81
C17-23	**Submitted at Hearing** March 03, 2009 BC Hydro Annual Report 1988
C18-1	**BROOKFIELD RENEWABLE POWER INC. –** Letter dated July 3, 2008, from Michael Walsh, filing request for Registered Intervenor status
C18-2	**BROOKFIELD RENEWABLE POWER INC.** - Report dated March 6, 2009 filing comments from Jack Burkom, Director of Marketing

Exhibit No.	Description
C19-1	**CLOUDWORKS ENERGY INC. –** Letter dated July 3, 2008, from John Johnson, Director, filing request for Registered Intervenor status
C19-2	Cloudworks Energy Information Request No. 1 dated July 8, 2008
C19-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C20-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated July 3, 2008, from R. Brian Wallace, Bull Housser & Tupper, legal counsel filing request for Registered Intervenor status on behalf of Dan Potts and Lloyd Guenther
C20-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C20-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C20-4	Letter received January 12, 2009 filing Information Request No. 3 to BC Hydro
C20-5	Email from February 11, 2009 Re-commitment to low cost power
C20-6	**Submitted at Hearing** March 03, 2009 Transmission System Capital Plan F2010 and F2011 IR
C21-1	**BC SUSTAINABLE ENERGY ASSOCIATION & SIERRA CLUB OF CANADA BC CHAPTER (BCSEA ET AL) –** Letter dated July 3, 2008, from William J. Andrews, legal counsel, filing request for Registered Intervenor status
C21-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C21-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C21-4	Letter dated November 14, 2008 from William J. Andrews, legal counsel, filing Evidence
C21-4-1	**Submitted at Hearing** March 03, 2009 Re: Exhibit C21-4, Amended Table IV-l and Table IV-2
C21-4-2	**Submitted at Hearing** March 03, 2009 Re: Exhibit C21-4, Amended Exhibit JJP-2 And Supporting Spreadsheet Workpages
C21-5	Letter dated November 21, 2008 issuing Information Request No. 1 to COPE 378
C21-6	Letter dated December 18, 2008 filing responses to Commission Information Request No. 1
C21-7	Letter dated December 19, 2008 filing printed versions of the Excel spreadsheets filed in Exhibit C21-6

Exhibit No.	Description
C21-8	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C21-9	**Submitted at Hearing** March 02, BCSEA-SCBC Witness Aid
C21-10	**Submitted at Hearing** March 03, Direct Testimony of Thomas Hackney
C21-11	**Submitted at Hearing** March 03, Resume of Thomas Hackney
C22-1	**TOWN OF FORT NELSON –** Online web registration received July 3, 2008, from Chris Morey, filing request for Registered Intervenor status
C22-2	Letter dated September 18, 2008 filing support for BC Hydro
C23-1	**HORIZON TECHNOLOGIES INC. / ENERGY SOLUTIONS FOR VANCOUVER ISLAND SOCIETY (ESVI) –** Online web registration received July 3, 2008, from Ludo Bertsch, filing request for Registered Intervenor status
C23-2	Letter dated July 17, 2008, filing Information Request No. 1 to BC Hydro
C23-3	Letter dated September 11, 2008 filing Information Request No. 2 to BC Hydro
C23-4	Information Request No. 1 to Independent Power Producers Association of BC dated December 8, 2008
C23-5	Letter dated December 9, 2008 filing submission to represent Okanagan Environmental Industry Alliance ("OEIA") and Island Transformation.Org ("ITO")
C23-6	Letter dated January 12, 2009 filing Information Request No. 3 to BC Hydro
C23-7	**Submitted at Hearing –** February 23, 2009 BCH Organizational Structure
C23-8	**Submitted at Hearing** February 23. 2009 **–** Email received White House Joint Effort on Recovery
C23-9	**Submitted at Hearing** March 05. 2009 Cumulative Energy Savings at Customer Meter
C23-10	**Submitted at Hearing** March 05. 2009 BC Hydro Power Smart Brochure
C24-1	**FORTISBC INC. –** Online web registration received July 3, 2008, from Joyce Martin, filing request for Registered Intervenor status

Exhibit No.	Description
C25-1	**ELK VALLEY COAL CORPORATION (EVCC) –** Letter dated July 4, 2008, from J. David Newlands filing request for Registered Intervenor status
C26-1	**HOWE SOUND PULP & PAPER LIMITED PARTNERSHIP** - Letter dated July 7, 2008, from Pierre Lamarche, Manager, filing request for Registered Intervenor status
C27-1	**CAMPBELL, JAMES** - Facsimile dated July 10, 2008 requesting late Intervenor status
C28-1	**CANADIAN GEOTHERMAL ENERGY ASSOCIATION (CANGEA)** - Letter dated July 14, 2008, from Alison Thompson, filing request for late Registered Intervenor status
C28-2	Letter dated July 17, 2008 filing Information Request No. 1 to BC Hydro
C29-1	**MOUNTAIN POWER INC. (MPI)** - Letter dated July 11, 2008, from Karyn Lippencott, filing request for late Registered Intervenor status
C30-1	**CITY OF NEW WESTMINSTER – ELECTRIC UTILITY COMMISSION** - Letter dated July 9, 2008, from R.E. Carle, General Manager, filing request for late Registered Intervenor status
C31-1	**FINAVERA RENEWABLES –** Online web registration received July 14, 2008, from Carlie Smith, filing request for Registered Intervenor status
C32-1	**PRISTINE POWER INC. –** Online web registration received July 14, 2008, from Eli Walker, Farris Vaughan Wills & Murphy, legal counsel, filing request for Registered Intervenor status
C32-2	Letter dated July 16, 2008, filing notice of participants who will attend the Procedural Conference
C33-1	**TEXADA ACTION NOW COMMUNITY ASSOCIATION (TAN) –** Letter received August 4, 2008, from Richard Fletcher, Vice Chair, filing request for late Registered Intervenor status
C33-2	Letter dated September 10, 2008, filing Information Request No. 1 to BC Hydro
C33-3	Letter dated November 14, 2008 filing submission regarding LNG facility
C33-4	Email dated November 25, 2008 filing comments on the procedural process
C33-5	Letter dated January 5, 2009 filing response to Commission Information Request No. 1

Exhibit No.	Description
C33-6	Email received February 5, 2009 TAN OPENING STATEMENT
C34-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR) –** Letter received August 5, 2008, from Jennifer Champion, Policy Analyst, filing request for late Registered Intervenor status
C35-1	**INVENERGY WIND CANADA ULC –** Online web registration received July 28, 2008, from Hally Hofmeyr, filing request for late Registered Intervenor status
C36-1	**NAIKUN WIND DEVELOPMENT INC. –** Request for Late Intervenor status dated December 24, 2008 from Paul Taylor
C36-2	Letter dated January 12, 2009 filing Information Request to BC Hydro
C36-3	Letter dated February 11, 2009 NaiKun-Appoint Counsel

INTERESTED PARTY DOCUMENTS

D-1	**UMA-AECOM ENGINEERING –** Online web registration received June 18, 2008, from Richard Harper, filing request for Interested Party status
D-2	**SEA BREEZE POWER CORP. –** Online web registration received July 2, 2008, from Monique Stevenson, filing request for Interested Party status
D-3	**ASPEN COMMUNICATIONS LTD.** – Online web registration received July 7, 2008, from David Read, filing request for Interested Party status
D-4	**CHINOOK POWER CORP. -** Online web registration received July 14, 2008, from Stephen Cheeseman, filing request for Interested Party status
D-5	**NAIKUN WIND DEVELOPMENT INC. -** Online web registration received July 16, 2008, from Tony Fogarassy, filing request for Interested Party status
	Change in status to Intervenor December 29, 2008 – see C36-1
D-6	**SKY POWER CORP. -** Online web registration received July 16, 2008, from Cory Basil, filing request for Interested Party status
D-7	**ELLIOTT ENERGY SERVICES LTD. -** Online web registration received August 13, 2008, from John Elliott, filing request for Interested Party status

Exhibit No.	Description
D-8	**GREENWING ENERGY –** Online web registration dated August 27, 2008 from Jake Gray requesting Interested Party status
D-9	**MORRISON, JOHN PAUL –** Online web registration dated September 8, 2008 requesting Interested Party status
D-10	**RECOLLECTIVE CONSULTING –** Online web registration received October 10, 2008 from Eesmyal Santos-Brault, requesting Interested Party status
D-11	**BERKHOUT, TOM -** Online web registration dated January 28, 2009 requesting Interested Party status
D-12	**CANADIAN WIND ENERGY ASSOCIATIONS -** Online web registration dated January 28, 2008 from Mr. David Huggill requesting Interested Party status
D-13	**WIND PROSPECT INC. -** Online web registration dated February 2, 2009 from Mr. Jeffrey Norman requesting Interested Party status
D-14	**ANDREW FLOSTRAND** -Online web registration received February 15, 2009 filing request for Interested Party status
D-15	**TRAVIS BRAITHWAITE** -Online web registration received February 18, 2009, from **TRAVIS BRAITHWAITE**, filing request for Interested Party status