Integrated Resource Plan

Chapter 1

Introduction and Context

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1.1 Introduction to and Structure of the Integrated Resource Plan

British Columbia Hydro and Power Authority (**BC Hydro**) submits this Integrated Resource Plan (**IRP**) to the British Columbia (**B.C.**) Minister of Energy and Mines (**Minister**) in accordance with section 3 of the B.C. *Clean Energy Act*[1] (***CEA***). This IRP presents a set of recommended actions consistent with the *CEA* objectives that ensure BC Hydro customers will continue to receive cost-effective, reliable electricity with manageable risks.

1.1.1 Approval Request and IRP Submission Cycle

BC Hydro requests that the Lieutenant Governor in Council (**LGIC**) approve the IRP pursuant to subsection 4(1)(a) of the *CEA*.

BC Hydro submitted its IRP to the Minister on August 2, 2013. By letter dated August 23, 2013 the Minister requested that BC Hydro conduct a final round of consultation on the IRP to be completed no later than October 18, 2013 and re-submit the IRP on or before November 15, 2013.

BC Hydro modified the IRP submitted to the Minister on August 2, 2013 in response to:

1. The Minister's request that BC Hydro revise its IRP to support the clean energy sector in B.C. and promote clean energy opportunities for First Nations communities. This resulted in a new IRP Recommended Action to, among other things, increase the Standing Offer Program (**SOP**) annual target from 50 gigawatt hours per year (**GWh/year**) to up to 150 GWh/year to enable more small-scale projects in communities throughout BC Hydro's service area, and promote First Nation participation in the clean energy sector. BC Hydro's proposed Clean Energy Strategy is described in Chapter 8 of this IRP.

[1] S.B.C. 2010, c.22.

2. Comments received during the IRP consultation period ending October 18, 2013. The consultation-related comments are summarized in Chapter 7, which provides links to the various IRP chapters that have been modified in response to comments received.

There is a need for an evidentiary cut-off date as preparing forecasts and updating analysis based on new forecasts is a series of complex processes that take time. Aside from IRP consultation comments and related changes, the cut-off for new information for the IRP is August 2, 2013.[2] Thus for example the description of greenhouse gas (**GHG**) regulatory developments is current up to August 2, 2013.

Subsection 3(6)(b) of the *CEA* provides that subsequent IRPs must be submitted every five years after submission of this first IRP unless a submission date is prescribed by LGIC regulation. The submission date for the next IRP is August 2018 in the absence of such a regulation. Subsection 3(7) of the *CEA* enables BC Hydro to submit an amendment to an approved IRP. BC Hydro plans to review the IRP in the fall of 2015, at which time BC Hydro expects to have further information concerning, among other things:

- Demand Side Management (**DSM**)[3]
- Electricity Purchase Agreement (**EPA**) renewal pricing and volumes
- An environmental assessment decision concerning Site C from the B.C. Ministers of Environment and of Forests, Lands and Natural Resource Operations, and the federal Minister of Environment
- Liquefied natural gas (**LNG**) proponent decisions to take service from BC Hydro and/or final investment decisions.

[2] The Independent Power Producer (**IPP**) information and forecast used in this IRP is based on the April 2013 update. There is negligible difference between the April and August version with an increase of 2 GWh of IPP post-attrition firm energy in the August 2013 version.

[3] The term Demand Side Management is synonymous with the section 1 *CEA* definition of the term ‘demand-side measures’. BC Hydro uses the acronym DSM in this IRP to refer to both terms.

A decision to submit an amendment prior to the next IRP will depend on the outcome of this review, which BC Hydro plans on sharing with interested parties including IRP Technical Advisory Committee members, First Nations and the public.

1.1.2 BC Hydro

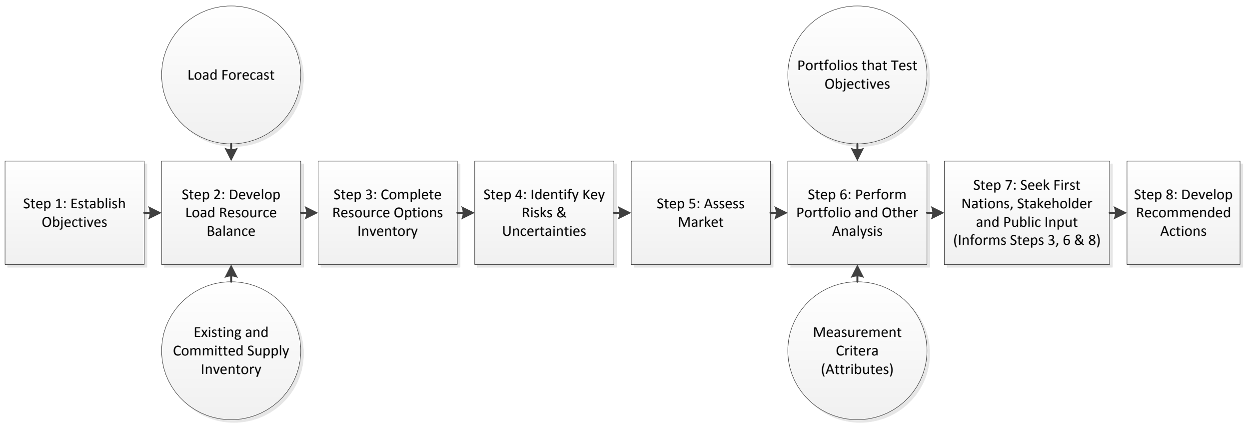
BC Hydro is a Crown corporation established in 1962 under the *B.C. Hydro and Power Authority Act.*[4] Among other things, BC Hydro is mandated to generate, conserve, acquire and supply electrical power and related products. BC Hydro is the third largest electric utility in Canada, serving about 95 per cent of B.C.'s population in a service area that encompasses most of B.C. with the exception of the City of New Westminster and the south-central part of the Province which is served by FortisBC Inc. As a public utility BC Hydro has an obligation to serve its existing 1.9 million residential, commercial and industrial customer accounts and any future customers in its service area.

1.1.3 IRP Process and Structure

Fundamentally, the IRP addresses broad questions of how much, when and what new resources should be advanced to meet customer electricity needs. The IRP involves eight steps as set out in Figure 1-1 and described below; the description also provides the relevant IRP chapter reference.

4 R.S.B.C. 1996, c.212.

Figure 1-1 IRP Planning Process



Step 1 – Establish planning objectives.

The first step in the resource planning process is to develop planning objectives. The planning objectives provide the basis on which to identify and compare alternative resource options.

Section 1.2 below describes the IRP planning objectives, which are:

1. Adhere to good utility practice by meeting the energy and capacity planning criteria. BC Hydro's need for new electricity resources is established using two planning criteria – firm energy and dependable capacity:
   - Firm energy is the amount of electricity required over a period of time, measured in GWh/year
   - Peak demand is the maximum hourly demand on BC Hydro's system, measured in megawatts (**MW**) and is met with dependable capacity
2. Align with the "British Columbia's energy objectives" (referred to as the ***CEA* energy objectives**) set out in section 2 of the *CEA* which BC Hydro must respond to in this IRP. There are 16 *CEA* energy objectives including the legally-binding self-sufficiency requirement contained in subsection 6(2) of the *CEA*.

*Step 2 – Develop 20-year Load-Resource Balances (**LRBs**).*

To determine need, BC Hydro's annual energy and peak capacity LRBs are analyzed for the BC Hydro integrated system.[5] A LRB is the difference between BC Hydro's Load Forecast – which projects BC Hydro customer demand (referred to as '**load**') over a 20-year period – and supply from existing and committed resources.[6] There is a gap (i.e., shortfall) if forecasted customer demand exceeds the existing and committed resources available to serve such load; and there is a surplus if available resources exceed forecasted load.

Chapter 2 provides the energy and capacity LRBs for the 20-year IRP planning horizon. Based on the December 2012 Load Forecast and the most recent assessment of existing and committed supply-side resources, BC Hydro is forecasting:

- A need for energy resources beginning in Fiscal (**F**) F2017[7,8]
- A need for capacity resources beginning in F2017

Chapter 2 also examines potential LNG load. As of the date of submission of this IRP, there are 12 publicly-announced LNG projects proposed for Kitimat and Prince Rupert areas of the B.C. North Coast, as well as Squamish in the Lower Mainland and Campbell River on Vancouver Island:

[5] BC Hydro's integrated system is an interconnected network of transmission lines, distribution lines and substations linking generating stations to one another and to customers throughout BC Hydro's service area, excluding isolated customers who are connected to free-standing generating facilities. Some of BC Hydro's customers live in areas that are not served by the integrated system. Local generation serves these Non-Integrated Areas (**NIAs**). Unless otherwise indicated, this IRP does not address NIAs.

[6] Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal (natural gas-fired) generating resources, as well as IPP facilities delivering electricity to BC Hydro. Committed supply-side resources are resources for which material regulatory and BC Hydro executive approvals have been secured. Refer to section 2.3 for further details.

[7] All years in this IRP are stated in fiscal years (F20xx) ending March 31, except where otherwise noted.

[8] BC Hydro has only considered the requirements for additional resources in the planning horizon of F2017 to F2033. Operational shortfalls shown in F2014 to F2016 may be met through conservation, economic market purchases, greater use of thermal (natural gas-fired) generation resources or greater drawdown of major reservoirs.

- Potential LNG load consists of: (1) compression load, which is the energy required by the main liquefaction compressors that cool natural gas into liquid form and represents the majority of LNG facility requirements; and (2) non-compression load, which refers to the rest of LNG facility power demand including other compressors, pumps, control systems, loading terminal equipment, lighting and office requirements. Non-compression load typically accounts for about 15 per cent of overall LNG facility energy requirements.
- LNG projects typically require export licences from the National Energy Board and environmental assessment-related authorization through the B.C. *Environmental Assessment Act* [9] (***BCEAA***) and/or *Canadian Environmental Assessment Act* [10] (***CEAA***). In addition to the status of regulatory approvals, important LNG project decision-making steps that will inform BC Hydro's plans are the status of front-end engineering design and feasibility studies and final investment decisions. To date, no LNG project proponent in B.C. has made a final investment decision.
- After discussions with LNG proponents and review of LNG project descriptions submitted to the B.C. and Canadian environment assessment agencies, BC Hydro understands that proponents of the larger LNG projects generally will not be requesting electricity service for compression loads. Larger scale LNG proponents may request service from BC Hydro for non-compression load,[11]

[9] S.B.C. 2002, c.43.

[10] S.C. 2012, c.19, section 52 (in force July 6, 2012).

[11] Project Description (section 5.9) for LNG Canada dated March 21, 2013: "Each LNG liquefaction train will utilize natural gas-fired direct drive for the main refrigeration compressors to produce LNG. The LNG facility and marine terminal will require electrical power to operate all other supporting facilities and infrastructure. Approximately 90 MW of electrical power will be required for Phase 1 and approximately 150 MW will be required at full build-out. There are currently two options being considered for the electrical power requirements including: power supply option 1 – electrical power sourced from the BC Hydro electrical grid; and power supply option 2 – new electrical generation installed at the LNG facility site".

Project Description (section 2.13) for Prince Rupert LNG dated April 2013: "The facility will be designed to be self-sufficient for all power needs by onsite combustion of a proportion of the natural gas supply to the Facility in gas turbines … .Where power from the grid is available and reliable it is anticipated that it will be used for 'utility power' [which is defined as "electrical power generators for lighting, to power pumps, etc."] in preference to onsite electrical power generated by gas turbines". The Prince Rupert LNG utility power requirements are stated to be 140 MW for Phase 1 and 200 MW for Phase 2.

while smaller-scale LNG projects such as the Woodfibre LNG project proposed for an industrial site near Squamish, B.C. may take service for both compression and non-compression load. BC Hydro estimates that LNG projects could add between about 800 to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Based on discussions with the B.C. Government and LNG proponents, the expected LNG load is about 3,000 GWh/year corresponding to about 360 MW of peak demand (referred to as **Expected LNG**).

Step 3 – Determine and characterize the resource options that are economically and technically feasible to fill the energy and capacity gaps.

BC Hydro considered a wide variety of resource options for addressing the forecasted energy and capacity LRB gaps.

Chapter 3 profiles: (1) DSM which consist of conserving energy, promoting energy efficiency and other measures to reduce the customer demand that BC Hydro must serve; (2) supply-side generation resources that are consistent with the *CEA* energy objectives; and (3) transmission resource options that support the delivery of power generation to customer loads. Potential resources are described using financial and technical, environmental and economic development attributes reflecting information from project experience, First Nations, public and stakeholder input, and consultant studies. Chapter 3 concludes with: (1) a summary of the adjusted Unit Energy Cost (**UEC**) or Unit Capacity Cost (**UCC**) of the viable resources that are analyzed further in the IRP; and (2) the list of resources that are not considered further because they are not viable (e.g., legally barred, or are not technically or economically feasible).

Step 4 – Develop a resource analysis framework to identify key risks and uncertainties, balance relevant considerations and compare resource alternatives.

Chapter 4 summarizes the considerable uncertainty BC Hydro faces in its long-term resource planning environment, including:

- Load growth and the risk that load growth exceeds or falls below expectations
- DSM delivery risk – the risk that the response to DSM initiatives is less than planned or required
- Market conditions, including prices

These uncertainties and the 20-year IRP planning time frame underscore the need to de-emphasize single point estimates for forecasting load and the LRBs; rather, uncertainties with load forecasting, DSM and supply-side options translate into a range of future resource requirements and contingency plans.

Chapter 4 also addresses the question of how to manage the costs of energy from F2013 to about F2018 after implementation of the DSM target and supply-side resource decisions such as renewals of existing IPP contracts (referred to as EPAs). BC Hydro examined potential ratepayer impacts and the risks of making adjustments to IPP EPAs and the DSM target, and concludes it should reduce near-term costs while maintaining longer-term savings.

The remainder of Chapter 4 sets out the portfolio modelling and longer-term decision making process. The viable resources are used to develop alternative resource portfolios to analyze the comparative cost and other attributes. This analysis is consistent with the British Columbia Utilities Commission's (**BCUC**) Resource Planning Guidelines[12] and is considered a best practice for IRP analysis. However, while a rigorous evaluation of portfolio cost performance across a range of risks and uncertainties lends insights into decision making, it does not replace prudent utility judgment or the need to consider qualitative factors.

Step 5 – Identify and assess market risks and uncertainties.

Given among other things the *CEA* subsection 3(1)(d) requirement to provide a description of the potential for B.C. to meet any export demand, Chapter 5 contains

[12] Available at www.bcuc.com/Documents/Guidelines/RP Guidelines.12-2003.pdf.

projected prices for natural gas, GHG offsets and Renewable Energy Credits resulting in forecasted spot market electricity prices at the Mid-Columbia trading hub near the Washington/Oregon border ranging from about $25 per megawatt hour (**/MWh**) to $40/MWh over the next 20 years. BC Hydro concludes at the end of Chapter 5 that there are no suitable market opportunities that warrant the development of new, additional clean or renewable resources for the purpose of exporting electricity for the foreseeable future.

Step 6 – Develop portfolios and measurement criteria in order to conduct a portfolio analysis of viable resources.

Chapter 6 reviews the DSM target set in the 2008 Long Term Acquisition Plan (**LTAP**) of 7,800 GWh/year of energy savings, with associated capacity savings of 1,400 MW, in F2021 and concludes that this DSM target should be maintained. Chapter 6 also addresses supply-side resource requirements after implementation of the DSM target. BC Hydro concludes that based on portfolio and other analysis, Site C provides the best combination of financial, technical, economic development and environmental attributes and is therefore the preferred resource option to meet the need for energy and capacity after implementation of the DSM target. BC Hydro provided additional analysis concerning DSM and Site C in response to requests made during the consultation process.

Step 7 – Seek and consider input from First Nations and stakeholders.

Chapter 7 contains a description of BC Hydro's IRP-related consultations to date.

Step 8 – Prepare recommended actions that set out the steps BC Hydro plans on taking during the next five years.

Given the Minister’s request, BC Hydro prepared a Clean Energy Strategy which is described in Chapter 8. Actions underpinning the Clean Energy Strategy include:

- Undertaking EPA renewals that are cost-effective. BC Hydro plans to rely on EPA renewals to account for 1,200 GWh/year of energy by F2017, and 6,400 GWh/year of energy by F2033. Thus EPA renewals are a major resource that BC Hydro plans to rely on to meet future customer demand, second only to the DSM target in terms of energy volume.
- Increasing the SOP annual target from 50 GWh/year to up to 150 GWh/year. BC Hydro also proposes to introduce a “micro-SOP” component within the overall SOP annual target to enable projects in the range of 100 kilowatts (**kW**) to 1 MW, ensuring there is opportunity for projects of this size (larger than those enabled through Net Metering). Projects of this size are often customer-based and often align with the scale of projects that First Nations communities wish to undertake. BC Hydro plans on engaging First Nations and IPPs on how to introduce a new element to the SOP eligibility rules to encourage First Nations participation.
- Preparing plans to acquire energy as part of BC Hydro’s Contingency Resource Plans (**CRPs**) should demand exceed what BC Hydro has forecasted. As part of the fall 2015 review of the IRP, BC Hydro will review the need for new resources;
- Pursuing cost-effective bilateral agreements where warranted;
- Regularly updating BC Hydro’s inventory of clean or renewable resources as part of the Resource Options Report process.

Chapter 9 summarizes specific Recommended Actions, including the costs of and the associated regulatory and other risks of pursuing such actions. The Recommended Actions do not, by themselves, commit BC Hydro to any specific projects identified over the planning horizon. Specific initiatives and projects, such as DSM and the construction of generation facilities and transmission lines, have additional consultation and approval requirements which are described in Chapter 9. BC Hydro's Recommended Actions align with B.C. Government policy as reflected in the *CEA* energy objectives, the 2007 BC Energy Plan,[13] British Columbia's Natural Gas Strategy and Liquefied Natural Gas Strategy[14] (referred to as the LNG Strategy), the Climate Action Plan[15] and other Provincial Government policy documents referred to in the IRP.

The IRP consists of nine chapters referenced above and a series of technical appendices. The IRP appendices, included as separate volumes, are comprised of several significant studies conducted to support the IRP, including the December 2012 Load Forecast, the Resource Options Report and related updates, the electricity price forecast for the Western Electricity Coordinating Council (**WECC**)[16] region and the IRP consultation reports. A glossary defining key terms and referencing abbreviations used in the IRP is also attached as Appendix 1A.

1.2 Planning Objectives

This section describes the IRP planning objectives that are used to analyze resource options and portfolios to inform Recommended Actions.

1.2.1 Setting the IRP Planning Objectives

The IRP planning objectives were developed within a statutory and policy framework. Objectives include those which involved meeting criteria (energy and capacity planning criteria) and others that are targeted and considered in light of competing objectives. Specifically, the IRP planning objectives are derived from the following requirements:

[13] *The BC Energy Plan: A Vision for Clean Energy Leadership*, www.energyplan.gov.bc.ca.

[14] B.C. Ministry of Energy and Mines, *British Columbia's Natural Gas Strategy: Fuelling B.C.'s Economy for the Next Decade and Beyond*, February 3, 2012, www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf; and *Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry*, February 3, 2012, www.gov.bc.ca/popt/down/liquefied_natural_gas_strategy.pdf.

[15] www.gov.bc.ca/premier/attachments/climate_action_plan.pdf.

[16] The WECC territory is composed of two Canadian provinces – B.C. and Alberta; parts of 14 western United States (**U.S.**) states (California, Nevada, Arizona, Utah, Idaho, Oregon, Washington state, Wyoming, most of Montana, Colorado and New Mexico, and a part of South Dakota, Nebraska and Texas); and the northern portion of Baja California, Mexico.

- Good utility practice, which includes the practices, methods and acts engaged in by a significant portion of the electric utility industry in the WECC, the region in which BC Hydro operates, and statutory obligations including the obligation to serve contained in section 39 of the B.C. *Utilities Commission Act* [17] (***UCA***). BC Hydro's service obligation and good utility practice establish a baseline for the energy and capacity criteria described in section 1.2.2 below.
- Subsection 6(2) of the *CEA* is legally binding and requires BC Hydro to achieve electricity self-sufficiency by holding the rights to enough electricity generated in B.C. including a prescribed reliance upon Heritage assets to meet BC Hydro's "electricity supply obligations by 2016 and each year after that".[18] The self-sufficiency requirement augments the planning criteria established by BC Hydro's service obligation and good utility practice.
- The *CEA* energy objectives discussed in section 1.2.3 below, and other directions established by the B.C. Government in the *CEA* and pursuant to policy documents such as the 2007 BC Energy Plan, establish planning objectives that are to be targeted and considered in light of other competing objectives. Other relevant B.C. Government legislation and policy directives are described in section 1.2.4 below.

1.2.2 Planning Criteria

BC Hydro uses both generation and transmission planning criteria. Generation planning criteria are used to evaluate when generation resources are required to maintain a reliable and adequate supply of electricity to meet load. These generation planning criteria focus on the reliable and adequate supply of capacity and energy at the bulk system level.[19] BC Hydro applies the transmission planning criteria to

[17] R.S.B.C. 1996, c.473.

[18] Section 2 of the B.C. *Energy and Mines Statutes Amendment Act*, *2012* repealed the 3,000 GWh/year insurance requirement, formerly found in subsection 6(2) of the *CEA*. Section 2 is in effect; S.B.C. 2002, c.27. Refer to Chapter 2, where the LRBs are presented with no insurance.

[19] The bulk transmission system is the major 230 kV and higher voltage lines or 'backbone' of the transmission system that provide large amounts of power to BC Hydro's service area.

assess what bulk transmission resources are needed to deliver the planned supply-side resources to the major customer load centres. The IRP does not incorporate a detailed assessment of the effects of transmitting, transforming or distributing the electricity below the bulk level to the end-use customer.

In applying its generation planning criteria, BC Hydro considers both the annual energy demand and peak load on its electrical system. The generation and transmission planning criteria are requirements to be met in developing alternative resource portfolios. BC Hydro surveyed other electric utilities in the WECC with respect to their planning criteria and finds that BC Hydro's criteria are generally consistent with those used in the industry.

1.2.2.1 Generation Energy Planning Criterion

For predominantly hydroelectric utilities, the energy planning criterion is important because fuel supply (water) is limited. BC Hydro's generation energy planning criterion, prior to the *CEA* self-sufficiency requirement, was to meet its energy requirements with "firm" energy plus some degree of reliance on non-firm hydro energy backed up by market purchases. Firm energy is defined as the ability to meet load requirements under the most adverse sequence of stream flows as experienced by BC Hydro’s Heritage hydroelectric assets within the 60-year period between October 1940 and September 2000.

As described in section 1.2.1, the self-sufficiency requirement modifies the generation energy planning criteria that BC Hydro would otherwise have in place. The pre-self-sufficiency energy planning criterion establishes the firm energy reliance that BC Hydro could place on particular types of resources including how much non-firm hydro energy backed up by market purchases are appropriate. The *CEA* self-sufficiency requirement establishes two additional requirements: (1) the reliance upon the Heritage assets under a prescribed water condition which has been set as average water as described below;[20] and (2) that all other resources must be located within the Province of B.C.

By prescribing average water conditions for Heritage hydroelectric assets and that all other reliance must be from provincial resources effectively sets the degree to which BC Hydro can rely upon non-firm hydro energy backed up by market purchases at 4,100 GWh/year. As a result, the Heritage hydroelectric planned reliance is based upon average water and the planned reliance on all other resources is based upon their firm energy capability.

The energy reliance for each of BC Hydro's Heritage hydroelectric resources, thermal projects, and EPAs with IPPs is determined by application of the self-sufficiency and firm energy requirements as described below.

BC Hydro Heritage Hydroelectric Resources

For BC Hydro's Heritage hydroelectric resources, the Electricity Self Sufficiency Regulation[21] requires BC Hydro to achieve self-sufficiency by 2016 and each year after that, assuming that the Heritage hydroelectric resources are capable of producing no more than what they can produce under "average water conditions".

Until February 3, 2012, the Electricity Self Sufficiency Regulation required BC Hydro to plan for self-sufficiency based on an assessment of what BC Hydro's Heritage hydroelectric resources are capable of generating under the most adverse sequence of stream flows in respect of BC Hydro Heritage hydroelectric assets occurring within the 60-year period between October 1940 and September 2000, known as "critical water conditions". The system capability under critical water conditions is the firm energy capability of the system. The change in planning from critical water conditions to average water conditions increases the combined reliance on the

[20] Average water conditions are used to calculate the average annual heritage hydro energy output over the 60-year period between October 1940 and September 2000.

[21] B.C. Reg. 315/2010, as amended by Order in Council No. 036 (B.C. Reg. 16/2012, deposited February 3, 2012).

Heritage hydroelectric system non-firm energy backed up by market reliance in F2017 by about 4,100 GWh/year.

Amendments to Special Direction No. 10 to the BCUC[22] (**SD 10**) in 2012 are also relevant. Section 1 of SD 10 provides that the BCUC, in adjudicating BC Hydro applications, must use the new planning criterion of average water. Heritage hydroelectric capability (using average water) for purposes of SD 10 is defined in subsection 1(2) as 48,200 GWh/year.[23]

BC Hydro Heritage Thermal Resources

Firm energy for thermal resources such as natural gas-fired generation is the energy capability based on conservative estimates of plant availability factors or expected plant operation factors. Plant availability factors or operational are typically based on historical operating experience or, where applicable, industry statistics of similar facilities.

EPAs

For IPP hydroelectric resources, BC Hydro uses an assessment of the firm energy contribution to the system under critical water conditions (the most adverse sequence of stream flows occurring within the same 60-year period described above in respect of BC Hydro Heritage hydroelectric assets). With the degree of market back-up established in the Heritage hydro reliance and further restricted by the self-sufficiency requirement, IPP non-firm energy does not meet BC Hydro's energy planning criterion and is not relied upon to meet customer demand.

For IPP wind resources, their average energy production is relied upon for firm energy contribution since their annual variability is typically much lower and is independent of hydro inflows. For thermal projects under contract to BC Hydro

[22] B.C. Reg. 245/2006, as amended by Order in Council No. 035 (B.C. Reg. 17/2012, deposited February 3, 2012).

[23] This compares to SD 10's previous definition of such capability using critical water of 42,600 GWh/year.

through EPAs, their contractual firm energy commitments (where available) are relied upon for firm energy contributions since such EPAs would not typically contain significant non-firm energy due to higher fuel certainty. For thermal projects that do not have contractual firm commitments, their average energy production is relied upon for firm energy contribution.

1.2.2.2 Generation Capacity Planning Criterion

The generation capacity planning criterion is for utilities to ensure that there is sufficient installed generation capacity to reliably serve the instantaneous demand of the BC Hydro integrated system. BC Hydro applies a standard Loss of Load Expectation (**LOLE**) methodology for its evaluation of capacity reliability. An "adequate" generation system is defined as one that has an annual expectation of being unable to serve the daily peak demand of less than one day in 10 years. The one day in 10 years LOLE methodology has widespread use in the industry. For the BC Hydro system as a whole, the one day in 10 years criterion requires installed dependable capacity to exceed peak load by approximately 14 per cent (about 1,800 MW in F2021).

Resource availability is an important aspect of the LOLE methodology. BC Hydro uses dependable capacity to define the resource availability for BC Hydro hydroelectric facilities and thermal plants. Dependable capacity, measured in MW, is the amount that resources are capable of supplying to meet the instantaneous peak load for electricity with a high level of confidence.

Similar to the generation energy planning criterion discussed above, the self-sufficiency requirement modifies the generation capacity planning criterion. Prior to the self-sufficiency requirement, BC Hydro relied upon 400 MW of dependable capacity from the markets. Self-sufficiency requires generating facilities to be within the Province of B.C.; hence, there is no market capacity reliance.

1.2.2.3 Transmission Planning Criteria

BC Hydro uses a series of North American Electric Reliability Corporation (**NERC**)[24] planning criteria and WECC regional business practices in planning and designing the transmission system, many of which are industry-mandated reliability standards[25] and adopted by the BCUC. These standards detail performance criteria for meeting system adequacy and operating reliability requirements. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

One particular performance standard is achieving adequacy with a first single-contingency, or N-1, level of supply reliability. The N-1 criterion is the ability to withstand the loss of the most critical element (such as the largest transmission line, generator or transformer) under any normal system condition without having to interrupt firm electric service. One common exception to the application of the N-1 criterion is in areas served by a radial transmission connection. Radial lines are upgraded when the capacity of the existing radial line is exceeded (i.e., under a N-0 criterion) or if there are specific reliability performance needs. Decisions to upgrade radially-supplied areas to meet the full N-1 contingency criterion are evaluated on a case-by-case basis taking into consideration the actual system performance in that area, customer reliability requirements, and the cost/benefit of different upgrade options.

[24] NERC is the electric reliability organization for North America, subject to oversight by governmental authorities in the U.S. and Canada.

[25] BC Hydro is a member of WECC, which is a member of the NERC. BC Hydro plans and operates the transmission system in accordance with NERC planning and operating standards, augmented by WECC as well as its own standards. Many of the NERC/WECC standards are mandatory and have been adopted by the BCUC.

1.2.3 British Columbia's Energy Objectives

Subsection 3(1) of the *CEA* provides that in its IRP BC Hydro is to describe "what it (BC Hydro) plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives" set out in section 2 of the *CEA*. The subsection 2(a) self-sufficiency objective is unique because there is a legal requirement contained in subsection 6(2) of *CEA* that BC Hydro "must achieve self-sufficiency by the year 2016 and each year after that" for purposes of the IRP, and has been addressed above in section 1.2.2. BC Hydro groups the remaining 15 *CEA* energy objectives into four categories – Ratepayer Impact, Economic Development, Clean/Renewable/DSM and GHG Impacts, and Exports. Table 1-1 sets out how the IRP responds to these four categories of energy objectives. Overall, BC Hydro is of the view that the IRP represents the right balance of proposed cost-effective resource actions to meet customer reliability requirements while addressing environmental concerns and adhering to legislated and B.C. Government policy parameters.

Table 1-1 Summary of IRP Response to *CEA* Energy Objectives

CEA Energy Objective	IRP Response
Ratepayer Impact	Three of the *CEA* energy objectives fall within in the 'Ratepayer Impact' category – 2(e), 2(f), 2(m).
2(f): "to ensure [BC Hydro's] rates remain among the most competitive of rates charged by public utilities in North America"	BC Hydro places priority on this objective given that BC Hydro has a service obligation pursuant to section 39 of the *UCA* in accordance with its tariffs, the fact that the IRP is designed to address customer electricity demand and because of BC Hydro's relationship with its customers. In the IRP BC Hydro generally uses the BCUC's definition of 'cost-effectiveness', which in addition to low cost includes schedule/deliverability risk, reliability, timing, location and environmental impacts. BC Hydro considers that the recommended actions in Chapter 9 are the most cost-effective way (consistent with other requirements) to reduce costs in the short-term consistent with other requirements, meet the projected longer-term energy and capacity load/resource gaps, and therefore the optimal way to reduce revenue requirements and ensure that BC Hydro's rates remain competitive. Refer to Chapter 6, where BC Hydro emphasizes: (1) portfolios with the lowest Present Value (**PV**) costs; and (2) the lowest UECs or UCCs when examining potential resources. BC Hydro's approach is consistent with the BCUC's decision concerning BC Hydro's project evaluation methodology in the 2006 Integrated Resource Plan (**IEP**)/Long-Term Acquisition Plan (**LTAP**),[26] where the BCUC noted that an economic test consisting of levelized cost (i.e., UEC) and PV analysis was the more important test, and the ratepayer impact test was a secondary, less material test because among other things the PV economic test should be reasonably correlated with the incremental rate impact attributable to a project. Nevertheless, in response to comments received during the consultation process BC Hydro provides comparative rate impact analysis for several portfolios in section 6.10.[27]

[26] *In the Matter of British Columbia Hydro and Power Authority and 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan*, Decision, May 11, 2007 (**2006 IEP/LTAP Decision**), pages 183-208.

[27] BC Hydro examined whether other public utilities in the first (lowest rate) quartile produce long-term rate forecasts. The public utilities examined are: Hydro-Québec, Manitoba Hydro, Seattle City Light, Florida Power & Light, CenterPoint Energy (Houston), Nashville Electric and Pacific Power & Light. Both Hydro- Québec and Manitoba Hydro provide a survey of rates but only for the current year and/or previous years. For example, Manitoba Hydro's most recent rate comparison survey reviewed rates that are in place as of May 1, 2013. The 2013 Manitoba Hydro rate comparison survey found that BC Hydro's monthly bills and average prices remain generally within the first (i.e., lowest rate) quartile of public utilities surveyed. Very few major public utilities provide long-term rate forecasts publicly – Manitoba Hydro is the only major public utility that BC Hydro is aware of that does so. As a result, there is insufficient breadth of information available for BC Hydro to undertake a meaningful comparison of long-term rate forecasts over the planning period.

CEA Energy Objective	IRP Response
2(e): "ensure that [BC Hydro's] ratepayers receive the benefits of the heritage assets…" 2(m): "to maximize the value … of British Columbia's generation and transmission assets for the benefit of British Columbia"	The Recommended Actions outline how BC Hydro is advancing cost-effective upgrades at its existing generation facilities in a staged manner and what transmission projects it is pursuing. In addition, the impact of intermittent resources are included within the evaluation of alternatives in Chapter 6 to ensure that the value of the Heritage assets is both maximized and remains with BC Hydro's customers.
Economic Development	Two of the *CEA* energy objectives fall within the 'Economic Development' category – 2(k) and 2(l).
2(k): "encourage economic development and the creation and retention of jobs"	The Recommended Actions align with the section 2(k) objective by both maintaining the most cost-effective supply of electricity for its customers (including commercial and industrial entities) as well as through pursuit of DSM, the continued and expanded SOP, upgrades at existing BC Hydro facilities, transmission and Site C, all of which have direct and indirect economic benefits.
2(l): "foster the development of First Nation and rural communities through the use and development of clean or renewable resources"	Through the IRP consultation, BC Hydro sought input from First Nations on the topic of clean or renewable energy development in First Nations communities. BC Hydro is required to establish and maintain a SOP pursuant to subsection 15(2) of the *CEA*. In response to the Minister's request and feedback from First Nations and the clean energy sector through the IRP consultation process, BC Hydro is adjusting the SOP target from 50 GWh/year to 150 GWh/year, as well as increasing the net metering project size limit from 50 kW to 100 kW and creating a new process for small-scale DG projects from 100 kW to1 MW. This will enable greater participation from Municipalities; First Nation communities; Schools, and Commercial and Industrial customers] BC Hydro will also engage with First Nations on SOP eligibility rules that promote First Nation participation. Please refer to Chapter 8 for additional actions items intended to promote First Nations participation in the clean energy sector. Chapter 3 provides BC Hydro's resource option assessment, including how to access the information in Geographic Information System (**GIS**) format, which is a tool that can inform clean or renewable energy development. This *CEA* energy objective informed BC Hydro's IPP EPA portfolio actions. BC Hydro will honour its commitments on clean energy development made in various agreements with First Nations; refer to Chapter 8.

CEA Energy Objective	IRP Response
Clean/Renewable/DSM and GHG Impacts	Eight of *CEA* energy objectives fall within the 'Clean/Renewable and GHG Impact' category – 2(b), 2(c), 2(d), 2(g), 2(h), 2(i), 2(j), 2(o).
2(g) sets out the binding GHG reduction targets described in the B.C. Greenhouse Gas Reduction Targets Act 2(i) provides: "to encourage communities to reduce [GHG] emissions…" 2(h) states: "to encourage the switching from one kind of energy source or use to another that decreases [GHG] emissions in British Columbia"	The Recommended Actions put priority on capturing achievable, cost-effective DSM, and advancing generation resources which emit either no GHGs or relatively low levels of GHGs during operation such as Resource Smart projects at existing Heritage hydroelectric facilities and Site C. Electrification is a form of fuel switching; it is the process of switching specific end uses in the residential, commercial, transportation and industrial sectors from utilization of fossil-based fuels to using clean or renewable electricity. BC Hydro examined various electrification (GHG reduction) scenarios for the impact on incremental demand and undertook studies to understand how electrification could contribute to the provincial GHG targets. Refer to the analysis in section 6.7. As part of gas development in the province, BC Hydro continues to study the benefits and costs of electrifying the Fort Nelson/Horn River Basin region. BC Hydro will continue to work with the Provincial Government to assess electrification.
2(b) "to take [DSM] and to conserve energy, including the objective of [BC Hydro] reducing its expected increase in demand for electricity by the year 2020 by at least 66%"	The term "demand-side measure" (referred to as DSM in this IRP) is broadly defined in section 1 of *CEA* to include both rates and programs, among other measures. BC Hydro responded to the 2(b) objective by examining DSM portfolios in Chapter 6 that meet the 66 per cent *CEA* energy objective, and by targeting cost-effective and achievable DSM given the energy and capacity LRBs. BC Hydro is recommending a DSM target of 7,800 GWh/year of DSM energy savings by F2021. This target equates to about 78 per cent of BC Hydro's forecasted energy load increase by F2021 excluding Expected LNG load (and about 69 per cent with Expected LNG load by F2021).
2(c) "to generate at least 93% of the electricity in British Columbia from clean or renewable resources and build the infrastructure necessary to transmit that electricity"	Currently, BC Hydro's system is at about 95 per cent clean or renewable. See also the description in section 1.2.4 of the British Columbia's Energy Objectives Regulation[28], which regulation modifies this objective by providing that electricity to serve LNG is not included in the 93 per cent clean or renewable target. BC Hydro responded to the 2(c) *CEA* energy objective by examining portfolios in Chapter 6 that meet the 93 per cent clean or renewable objective and presenting Recommended Actions that support meeting this objective.

[28] B.C. Reg. 234/2012.

CEA Energy Objective	IRP Response
2(j) "to reduce waste by encouraging the use of waste heat, biogas and biomass" 2(d): "to use and foster the development in British Columbia of innovative technologies that support [DSM] and the use of clean or renewable resources" 2(o): "to achieve British Columbia's energy objectives without the use of nuclear power"	BC Hydro considers the renewal or extension of existing EPAs with bioenergy resources given that such resources can provide cost-effective dependable capacity, among other things; refer to Chapter 4. Concerning 2(d), BC Hydro's DSM program component contains a Technology Innovation component within its supporting initiatives. The SOP rules are set so that "completed prototype generation technologies" as well as "commercial operation generation technologies" are now eligible. In addition, the BCUC approved a proposal for BC Hydro's Net Metering tariff, which permits projects up to 100 kW. Previously projects were limited to 50 kW in size. With respect to 2(o), nuclear power will not form part of BC Hydro's preferred portfolio. Refer to Chapter 3.
Exports	Two of the CEA energy objectives fall within the 'Exports' category – 2(n) and 2(p).
2(n) " to be a net exporter of electricity from clean or renewable resources…" 2(p) "to ensure the [BCUC] … continues to regulate [BC Hydro] with respect to domestic rates but not with respect to expenditures for export, except as provided by [CEA]"	As set out in Chapter 5, BC Hydro's assessment concludes that there are no suitable market opportunities that warrant the development of new clean or renewable resources for the purpose of exporting electricity for the foreseeable future. As a result, BC Hydro is not proposing to pursue projects or contracts specifically to serve the export market as part of the Recommended Actions.

1.2.4 Additional B.C. Government Policy and Legislation

The LNG Strategy details the B.C. Government's commitment to LNG exports and outlines the priorities that are to guide development of this new industry, including the following: "To keep energy rates affordable". The LNG Strategy states that

> To offset the increased expense of operating new LNG facilities in the province, Government will ensure that LNG developers contribute capital for infrastructure development and to the electricity supply required to serve each operation.[29]

The British Columbia's Energy Objectives Regulation[30] modifies the *CEA* section 2(c) energy objective by providing that electricity to serve LNG demand is not included in the 93 per cent clean or renewable target. BC Hydro has not included

[29] *Supra*, note 11, page 8.
[30] B.C. Reg. 234/2012, deposited July 25, 2012.

LNG electricity load in its determination of the permissible natural gas-fired electricity generation. Section 6.2 sets out the maximum amount of new natural gas-fired electricity generation that could be built based on the December 2012 Load Forecast without LNG load and the implementation of the DSM target.

On March 25, 2013 the Minister issued Ministerial Order No. M073 entitled the Transmission Upgrade Exemption Regulation,[31] which exempts BC Hydro from Part 3 of the *UCA* with respect to described transmission facilities, including series capacitor stations and related facilities and equipment (referred to as the Prince George to Terrace Capacitors or **PGTC**). PGTC and other upgrades are expected to increase the ability of the North Coast 500 kilovolt (**kV**) transmission line to serve potential increased demand for electricity in northwest B.C. such as the LNG Canada project in the Kitimat area and other potential mine load between Bob Quinn and Dease Lake. BC Hydro is in the process of consulting with First Nations with respect to PGTC. Refer to section 9.3 for the LNG-related Recommended Actions.

1.3 IRP Recommended Actions

The Recommended Actions include:

- **Conservation** – DSM continues to be a major element in BC Hydro's Recommended Actions to fill the energy and capacity LRB gaps because it is cost-effective and has a minimal environmental footprint. After examining various DSM options, BC Hydro recommends maintaining the 2008 LTAP DSM target of 7,800 GWh/year of energy savings, with associated capacity savings of 1,400 MW, by F2021. For the F2014-F2016 period, BC Hydro recommends targeting DSM program expenditures at approximately the same level as the previous four years rather than increasing planned expenditures as set out in the F2012/F2014 Revenue Requirement Application to manage the cost of energy, while maintaining the ability to ramp back up to meet the recommended

[31] B.C. Reg. 140/2013.

DSM target. With the implementation of the DSM target and EPA renewals, BC Hydro is forecasting that absent any LNG loads it will require additional energy resources by F2028 and additional capacity resources by F2019. To meet Expected LNG load and assuming implementation of the DSM target, BC Hydro would require additional energy resources by F2022 and additional capacity resources by F2019.

- **EPA Portfolio Management** – As of August 2, 2013, BC Hydro has 127 EPAs, including 46 EPAs with IPPs whose projects are currently in development and have not reached their Commercial Operation Date (**COD**). To manage costs, BC Hydro began a review of its portfolio of pre-COD EPAs in early 2013, and identified projects that were in default and/or at an early stage of development and thus candidates for negotiation to terminate the EPA, to downsize the project, or to defer COD. BC Hydro analyzed the financial ratepayer benefits and the implementation risks associated with these potential EPA actions, and is proceeding with the termination, downsizing or deferral of more than 20 EPAs. As a result, BC Hydro forecasts a reduction of contracted energy by F2021 of about 1,800 GWh/year by F2021 (translating into a reduction in attrition-adjusted[32] forecasted firm energy supply of about 160 GWh/year).
- **Site C** – After taking into account the risks and uncertainties associated with the LRBs and the DSM target, BC Hydro recommends building Site C for its earliest in-service date (**ISD**) of F2024 subject to environmental assessment certification, fulfilling the Crown's duty to consult and if appropriate accommodate First Nations which may be potentially affected by Site C, and a decision by the B.C. Government to proceed to project construction. BC Hydro adopted a multi-stage approach for the planning and evaluation of Site C. BC Hydro entered Stage 3, the environmental and regulatory review stage, in April 2010. Stage 3 includes a harmonized environmental assessment process

[32] Attrition relates to the possibility that some of the IPP projects for which EPAs have been awarded will not proceed.

by federal and provincial regulatory agencies under *CEAA* and *BCEAA*. Should Site C receive environmental assessment certification at the end of Stage 3, Stage 4 would include a decision by the Province to proceed to construction with Stage 5 involving an approximately seven-year construction period, with one additional year for final project commissioning, site reclamation and demobilization.

- **Capacity Supply-side Options** – To manage incremental capacity needs for LNG loads and potentially higher non-LNG load growth, BC Hydro recommends investigating the acquisition of natural gas-fired generation and advancing two capacity Resource Smart projects in a staged manner with clear exit ramps: (1) natural gas-fired generation would be considered due to its ability to support the transmission system in the North Coast; (2) GM Shrum (**GMS**) Units 1-5 Capacity Increase project anticipated to provide about 220 MW of dependable capacity; and (3) Revelstoke Unit 6, which entails the installation of a sixth generating unit at Revelstoke Generating Station and anticipated to provide about 488 MW of dependable capacity. These two Resource Smart initiatives would contribute a limited amount of energy to BC Hydro's system. While both Resource Smart projects are being advanced as contingency resources, as future requirements become known a decision will be made on which of these resources will proceed first.
- **Transmission Resources** – To facilitate supplying the forecast load requirements with the recommended supply-side resources, BC Hydro recommends non-wire upgrades to: (1) the existing 500 kV transmission line from Williston Substation (**WSN**) near Prince George to Skeena Substation near Terrace with series and shunt compensation; and (2) the 500 kV transmission lines from GMS to WSN and Kelly Lake Substation. In addition, as described in section 1.2.4, BC Hydro will pursue PGTC and other upgrades to increase the ability of the North Coast 500 kV transmission line to serve potential increased demand for electricity in northwest B.C.

1.4 IRP Form Requirements and Role in Regulatory Proceedings

1.4.1 IRP Form Requirements

BC Hydro has met all of the IRP form requirements outlined in section 3 of the *CEA*:

- *"Consistent with good utility practice"*

  The IRP is an electric utility long-term resource plan balancing considerations of cost, risk, environmental and economic development attributes while meeting reliability criteria. The term "good utility practice" in this context means any of the practices, methods and acts engaged in by a significant portion of the electric utility industry in the development of long-term resource plans.
  BC Hydro examined the long-term resource plans of a number of electric utilities operating in the WECC including PacifiCorp, Portland General Electric and Puget Sound Energy, and BC Hydro is of the view that the IRP is consistent with the long-term resource plan development practices of those electric utilities, taking into account the differing legal and policy regimes. A common feature of long-term resource plans and thus of good utility practice is maintaining reliability of supply. Two competing objectives also pursued as part of good utility practice address minimizing the economic cost of delivering electricity services and minimizing the environmental impacts of electricity supply and use. BC Hydro's IRP is also guided by the BCUC's Resource Planning Guidelines.

- *"A description of [BC Hydro's] forecasts"*

  BC Hydro's assessment of its resource needs in Chapter 2 contains a description of the most recent, 20-year December 2012 Load Forecast.

- *"A description of what [BC Hydro] plans to do to achieve electricity self-sufficiency … including plans respecting the implementation of [DSM]; the construction or extension of facilities; the acquisition of electricity from other* *persons; and the use of rates to encourage [among other things] energy conservation or efficiency and the reduction of the energy demand [BC Hydro] must serve"*

BC Hydro is self-sufficient in energy in the short term; an energy surplus is forecast until F2018 if EPAs are renewed, but without implementation of the DSM target. The Recommended Actions demonstrate how BC Hydro intends to cost-effectively meet the medium to longer-term energy and capacity gaps through DSM and development of Site C, while also preparing for transmission and other measures to meet Expected LNG load.

- *"A description of the consultations carried out by [BC Hydro] respecting the development of the [IRP]"*

  This information is contained in Chapter 7. Under subsection 3(4) of the *CEA*, BC Hydro is required to carry out any consultations required by a Ministerial regulation. To date, no such regulation has been enacted. In respect of First Nations, and for the reasons set out in Chapter 7, BC Hydro determined that there is a legal duty to consult with First Nations regarding this IRP and that the duty is at the low end of the *Haida v. British Columbia (Minister of Forests)*[33] spectrum because the IRP itself has low to non-existent impacts as no specific projects or DSM measures are being directly implemented through the IRP itself. As set out in Chapter 9, the Recommended Actions require subsequent approvals prior to implementation. The IRP is not a substitute for these subsequent approval processes.

- *"A description of expected export demand …, the potential for British Columbia to meet that demand, the actions [BC Hydro] has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and the extent to which [BC Hydro] has arranged for contracts for the export of*

[33] 2004 SCC 73, Supreme Court of Canada, *Haida Nation v. British Columbia* (paragraph 39): "the scope of the duty to consult is proportionate to a preliminary assessment of the case supporting the existence of the right or title, and to the seriousness of the potentially adverse effect upon the right or title claimed".

electricity and the transmission or other services necessary to facilitate those exports"

As stated above, in Chapter 5 BC Hydro concludes that there are no actions BC Hydro should be taking because there are no foreseeable suitable market opportunities that warrant the development of new, additional clean or renewable resources for the purpose of exporting electricity. BC Hydro and Powerex Corp. will monitor export market developments as part of its ordinary course of business. Accordingly, BC Hydro is not proposing any projects or contracts needed to pursue export opportunities as part of the Recommended Actions.

- *"In the first integrated resource plan….a description of [BC Hydro's] infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the [IRP] is submitted"*

  BC Hydro’s transmission needs are discussed in section 6.8 and Appendix 6A of the IRP.

1.4.2 Role of IRP in Future Filings with BCUC

The *UCA* provides that the BCUC must "consider and be guided" by the IRP in adjudicating BC Hydro's applications for Certificate of Public Convenience and Necessity, expenditure requests under section 44.2 of the *UCA* for upgrades to existing facilities and DSM, and EPA filings under section 71 of the *UCA*. Thus, the IRP will be used as support and context for future BC Hydro filings with the BCUC.

The BCUC also maintains jurisdiction to separately approve CRPs[34] forming part of BC Hydro's Recommended Actions. CRPs are BC Hydro's alternative portfolios of resources to mitigate major risks inherent with the Recommended Actions, such as managing supply shortfall risks if the peak demand (capacity load) forecast is higher than anticipated or DSM does not deliver the projected capacity savings. The CRPs

[34] Pursuant to BCUC Directive 3 (page 109) of BCUC Order No. G-58-05 concerning the Open Access Transmission Tariff.

ensure that there are adequate transmission resources to deliver these contingency resources.

1.4.3 BCUC Directives

In its decision concerning BC Hydro's last long-term resource plan, the 2008 LTAP, the BCUC made a number of directives.[35] By letter dated November 1, 2010, BC Hydro advised the BCUC that it would be addressing a number of these directives in the IRP as follows:

Table 1-2 IRP Response to 2008 LTAP Directives

2008 LTAP Directive	IRP Response
4 – 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."	BC Hydro is energy self-sufficient, with a forecasted energy surplus until F2018 if EPAs are renewed but without implementation of the DSM target. The IRP sets out Recommended Actions to cost-effectively address the medium to longer-term gaps.
6 – Load Forecast: "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."	In the December 2012 Load Forecast (Chapter 2, Appendix 2A of the IRP), BC Hydro addressed the issue by correcting identified areas of overlap or documenting outstanding information gaps still to be resolved.
11 – DSM: "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."	Comparing risk-weighted UECs of DSM and supply-side options exactly in the manner suggested by the BCUC is not practical given the difficulty in quantifying DSM delivery risk. However, BC Hydro has built uncertainty into an incremental comparison of DSM and supply-side resources to respond to these concerns. Refer to Chapter 6.
13 – DSM: "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."	BC Hydro's analysis of the DSM target encompasses savings throughout the IRP 20-year study period.

[35] *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 (**2008 LTAP Decision**), section 8.0 "Summary of Directives".

In addition, there is one outstanding 2006 IEP/LTAP BCUC directive that is addressed in the IRP. With respect to the issue of potential effects of climate change on hydroelectric resources, the BCUC made the following directive:

> The Commission Panel concludes that BC Hydro should continue to assess the potential effects of climate change on its hydroelectric resources and that in addition to the activities it is currently involved in, BC Hydro should conduct statistical analyses of snow pack, annual precipitation and stream flows, freshet timing and other relevant variables and survey the relevant literature on an ongoing basis for relevant regional trends, with a view to assessing the impact on stream flows and on its major reservoirs. The Commission Panel directs BC Hydro to file a report with the Commission in its next IEP, identifying significant trends in the literature and summarizing the results of its statistical analyses of historical streamflows.[36]

Refer to section 2.3.1.7 and Appendix 2C of the IRP for the discussion of a climate change adaptation strategy framework to address the potential impacts of climate change on BC Hydro's operations and long-term planning.

[36] 2006 IEP/LTAP Decision, Directive 6, pages 56 and 216.