2008 Long Term Acquisition Plan

APPENDIX F9

Integrated System Planning Assumptions

2008 Long-Term Acquisition Plan

Appendix F, Section 9 Integrated System Planning Assumptions
(Rev: 00b01 (draft); 2008-Jun-112)

Report No. EPxxx EP File: EP-Criteria

Contents

A. INTRODUCTION

This document describes the integrated power system planning assumptions that BCTC and BC Hydro use in conducting integrated power system studies such as those associated with developing Long-Term Acquisition Plans (**LTAP**s).

This document was developed to respond to Directive 14 of the BCUC's 2007-May-11 IEP Decision[1]:

Directive 14:

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

B. GENERAL

This purpose of this document is to describe the assumptions used in the full range of planning studies from the very high level LTAP studies to the more detailed studies associated with the submission of an application for a Certificate of Public Convenience and Necessity (**CPCN**) for a specific project.
BC Hydro has interpreted "transmission planning assumptions" to be the following integrated system planning assumptions that BC Hydro provides to BCTC:

- Generation dispatch,
- Load forecast,

[1] See: http://www.bcuc.com/DecisionIndex.aspx for the BCUC's 2007-May-11 IEP Decision.

- Demand-Side Management (**DSM**),
- BC Hydro's Import/Export arrangements, and
- BC Hydro's Point-to-Point (**PTP**) transmission commitments.

B.1 THE INTEGRATED SYSTEM PLANNING PROCESS

This section briefly summarizes the various processes in which BC Hydro's planning assumptions are provided to BCTC for the purposes of transmission system analysis.

The treatment of BC Hydro's planning assumptions is expected to be consistent for all transmission planning studies regardless of whether the studies are conducted in or for a Network Integration Transmission Service (**NITS**) Application, a Transmission System Capital Plan (TSCP) or an Application for a CPCN for a specific transmission system reinforcement project. The level of detail simply increases at each stage of the study process.

In a LTAP when BCTC analyzes a wide range of load/resource portfolios that could number in excess of 100, detailed generation dispatch vs transmission system upgrade analyses are not conducted to optimize the level of transmission system upgrades for each portfolio. The transmission reinforcements to meet reliability criteria are simply chosen from a relatively small set of alternatives that have different capabilities and costs.

From the LTAP analysis, BC Hydro develops its Base Resource Plan (**BRP**) and a set of Contingency Resource Plans (**CRP**s) in accordance with the BCUC's Resource Planning Guidelines[2]. The BRP and CRPs are then included in the LTAP that is submitted to the BCUC for approval in accordance with the BCTC's Open-Access Transmission Tariff (**OATT**).

When the BRP and BCUC-approved CRPs are then submitted to BCTC in a NITS Application, a more detailed study is conducted including generation vs transmission trade-off analyses that follow from the re-dispatch options that BCTC identifies in accordance with Section 32.3 of the BCTC's OATT[3].

The NITS studies culminate in a Facilities Study Report that identifies the costs and schedules of each transmission reinforcement project associated with each of the BRP and CRPs. The TSCP and CPCN processes provide further opportunities to optimize the transmission reinforcement plan and the parameters of specific projects.

[2] BCUC Resource Planning Guidelines: http://www.bcuc.com/Guidelines.aspx

[3] BCTC's Tariff (OATT): http://www.bctc.com/transmission_scheduling/tariff_pricing/

C. GENERATION DISPATCH

C.1 GENERATING PLANT CAPACITY DEFINITIONS

This section provides a brief explanation of the various generating capacity terms. For any particular plant, each of these values may vary seasonally. For example, due to seasonal variations in reservoir elevations, GM Shrum and Mica have higher MCR and DGC values in August than February.

Maximum Continuous Rating **(MCR)**: this is the maximum plant output that can be sustained for at least one hour. The MCR value is the highest output that the plant would be able to produce under the most favourable conditions (eg, maximum head for hydro plants and coldest weather for gas turbines) considering the season.

Dependable Generating Capacity **(DGC)**: this is the capacity that a plant/unit can reliably provide for a required duration (3 hours/day to 16 hours per day depending on the load shape and dispatch order) each weekday during the two-week peak load period of the time of year (month or season) being studied.

Effective Load-Carrying Capability **(ELCC)**: this is the incremental amount of load demand that a plant can supply when it is added to the system based on maintaining the 1 day in 10 years Loss of Load Expectation (**LOLE**) generating capacity adequacy criterion. The ELCC of an intermittent resource like a wind farm is the capacity that is equivalent to that of a conventional generating plant (eg, large reservoir hydro plant) in terms of load supply reliability.

Reliability-Must-Run (**RMR**) Generating Capacity: This is the minimum level of generating capacity that a generator owner commits to have on line during peak load periods. Committing to providing less RMR capacity in a load centre would have the effect of advancing the need to reinforce the transmission system supplying that region.

For each generating resource BC Hydro specifies three plant capacities, DGC, ELCC and MCR.

In accordance with Directive 13 of the BCUC's 2007 IEP/LTAP Decision[4], BC Hydro requested[5] that BCTC undertake a set of integrated system reliability studies, the "**pre-NITS**" studies, to provide a basis for BC Hydro to develop guidelines for specifying generation dispatch assumptions for BCTC's deterministic transmission planning studies.

BCTC's pre-NITS studies are presently underway. Some preliminary results have been used in developing some of the guidelines described in this document.

Presently, the total aggregate RMR value for a region is the sum of the DGC values of all plants in the region with the exception of the Burrard plant (**BGS**). The DGC of the BGS plant is committed as RMR generating capacity only to the extent necessary to support the system until the ILM transmission system is reinforced. Thereafter, BGS capacity will not be committed as RMR. Following the completion of the "pre-NITS" studies, guidelines will be developed for regional RMR commitment limits. Those

[4] Directive 13 of the BCUC's 2007-May-11 IEP Decision (http://www.bcuc.com/DecisionIndex.aspx).

[5] 2007-Jul-31 BCH letter from John Rich to Janet Fraser.

guidelines are expected to define total regional RMR commitment limits that are somewhat less than the sum of the DGCs of the generating plants in a region (in effect assigning generation reserves on a regional basis).

C.2 GENERATION DISPATCH ASSUMPTIONS

BC Hydro determines future generating capacity requirements by periodically conducting probabilistic generating capacity adequacy studies that determine the generating capacity reserve required to achieve a LOLE of one day in 10 years, a criterion widely used by electric utility resource planners. BC Hydro's current load and generating resource characteristics indicate that a generating capacity reserve margin of 14% is appropriate for planning purposes.

In the operating time frame BCTC retains control over generation dispatch to protect reliability as per Article 5.4 of the Master Agreement[6] between BCTC and BC Hydro. However, for transmission planning studies, BC Hydro specifies regional generation dispatch requirements. For single- and multiple-contingency studies, BC Hydro specifies which plants could be automatically shed or run-back to meet NERC/WECC and BCTC's transmission planning disturbance performance standards and BC Hydro specifies the required regional aggregate generation dispatch for any prolonged single contingency.

For integrated system studies, the following generation dispatch assumptions are used in deterministic transmission planning studies that define transmission capacity requirements for <u>single-contingency (N-1)</u> conditions:

1. Generating Plants "<u>Upstream</u>" of the Cut-Plane being Studied:

    1.1. Each dispatchable generating plant is modeled as operating at the plant's MCR that is appropriate to the season.

    1.2. Intermittent generating resources (eg, wind farms and run-of-the-river hydro plants) are modeled as operating at their MCR levels in the pre-contingency state, but at their ELCC levels after any single contingency. Note that in actual operation, generator shedding or runback will often be applied to plants other than intermittent plants, but the aggregate effect would be equivalent to each intermittent resource in the upstream region being run-back to its ELCC level following the outage.

    1.3. Each Non-dispatchable plant with a high capacity factor like a co-generation, biomass or municipal solid waste facility is modeled as operating at its MCR level that is appropriate to the season if there are seasonal differences in the plant's output.

2. Each Generating Plant (including intermittents) <u>downstream</u> of the cut-plane being studied is modeled as operating at the greater of (i) the plant's minimum output level (possibly zero) or (ii) the plant's RMR commitment level. In high level studies such as those conducted in the LTAP process, the RMR commitment level is often assumed to be the plant's DGC (with the exception of BGS).

[6] BCH/BCTC Master Agreement: http://www.bctc.com/about_bctc/standards_agreements/designated_agreements/

3. BC Hydro may specify aggregate RMR generation levels that are less than the aggregate total of the DGCs of all generating plants in the regions downstream of the cut-plane being studied, considering the operating costs and reliability risks associated with specific plants and other factors such as guidelines that may be established to assign generating capacity reserves on a regional basis. BCTC is expected to identify the transmission system reinforcement needs consistent with the RMR commitment levels specified by BC Hydro.

4. BC Hydro will continue to commit the 905 MW dependable capacity of BGS as RMR only to the extent necessary to meet transmission planning criteria associated with BC Hydro's domestic load requirements and other contractual commitments until the ILM network can be reinforced. After the ILM grid is reinforced, Burrard capacity will not be committed as RMR.

In the past when BC Hydro's electricity needs were met almost entirely by dispatchable resources like medium- and large-reservoir hydro plants and conventional thermal plants, planning the transmission system to meet single contingency criteria usually determined the bulk system reinforcement requirements. However, intermittent resources like wind farms and small run-of-the-river hydro plants without significant storage are expected to provide a large part of BC's future electricity needs. It is therefore now more important to consider both single-contingency conditions as well as normal system conditions when determining the reinforcement requirements of the bulk electric system.

In general, to meet reliability requirements (ie, economics ignored) in deterministic transmission planning studies conducted to determine transmission requirements for normal system conditions (N-0), the generation dispatch assumptions are:

1. For plants located "upstream" of a cut-plane:

   1.1. dispatchable and non-dispatchable plants are modeled at their MCRs to determine transmission capacity requirements for the most onerous, but normal, system conditions (eg, the load level used in the study would be the level at which the performance criteria would be most difficult to meet).

   1.2. non- dispatchable plants must be able to operate continuously at their ELCC levels following single contingencies (N-1) with Remedial Action Schemes (**RASs**) provided to automatically reduce the aggregate generation in the upstream region from the MCR level to the aggregate ELCC level (ie, each plant need not be reduced to their ELCC level, but the aggregate generation in the entire region is reduced to the sum of the ELCCs of each intermittent plant in the region plus the MCR values of each dispatchable plant).

2. Each plant downstream of a transmission system cut-plane is modeled at the greater of its (i) minimum output level (possibly zero) or (ii) RMR commitment level. In high-level studies such as those conducted in the IEP process, the RMR commitment level is often assumed to be the plant's DGC (with the exception of the Burrard plant).

The results of the pre-NITS studies may refine the following generation dispatch criteria for future integrated system planning studies (ie, IEP, NITS, TSCP & CPCN studies).

- Interior Heritage Hydro Plant Dispatch: Presently Interior Heritage Hydro plants are modeled as operating at their MCR. In determining transmission requirements for N-1 contingencies the transmission system could be planned based on modeling Interior Heritage Hydro plants operating at their slightly lower DGC levels that would require a slightly lower level of transmission system capability.

- Coastal RMR: The current studies effectively hold the 905 MW DGC of BGS in reserve except as needed until 5L83 enters service. Presently, the aggregate DGC of all other Coastal plants is committed as RMR generation. The pre-NITS studies may lead to establishing a specific reliability guideline for load centre RMR commitment limits. Then, committing to lesser RMR amounts that would advance the need for transmission reinforcements would involve an economic trade-off between the cost associated with advancing ILM grid upgrades and the savings associated with committing less regional generating capacity (including Burrard capacity) as RMR.

- Transmission requirements for Intermittent Resources: Currently, when determining N-1 transmission capability requirements, wind and other intermittent resources are modeled at their ELCC levels if they are located "up-stream" of the transmission cut-plane being studied and at their DGC levels if they are located down-stream. The pre-NITS studies are expected to confirm that this practice is prudent, but the actual DGC and ELCC values (as a percentage of the intermittent resource's MCR) may be somewhat higher or lower than the current DGC and ELCC values used for different intermittent plant types.

D. LOAD ASSUMPTIONS

BC Hydro will provide non-coincident load forecasts for each individual transmission and distribution station, coincident load forecasts broken down into the four major regions, NI, SI, LM and VI, and a total integrated system coincident load forecast. The coincident load forecast values will include transmission system losses calculated from transmission loss factors provided by BCTC.

BC Hydro provides P50 (ie, 50% probability of non-exceedance in an individual year) and P90 (ie, 90% probability of non-exceedance in an individual year) for various load forecast scenarios, including the base load forecast scenario before future incremental DSM, and various load forecast scenarios with future incremental DSM. The load forecast confidence levels account for reasonably quantifiable uncertainties including weather, economic growth, electricity rate changes, and future incremental DSM savings as applicable.

BC Hydro provides both P50 and P90 load forecasts for each scenario in order to allow BCTC to choose and document the appropriate level of certainty for various transmission planning studies that assess regional transmission requirements. Typically, P50 load forecasts are used for N-1 contingencies studies and P90 load forecasts are used for system normal studies particularly for radial portions of the system. These studies are associated with a NITS Application or Transmission System Capital Plan (TSCP), but such regional transmission system studies are not part of the high-level LTAP studies that are primarily concerned with transmission requirements associated with future generation resources.

BC Hydro specifies the load forecast scenario(s) applicable to the LTAP BRP and each BCUC-approved CRPs that BC Hydro submits to BCTC in a NITS Update or Application.

E. IMPORTS AND EXPORTS

E.1 LONG-TERM FIRM POINT-TO-POINT (LTFPTP) COMMITMENTS

BCTC models all applicable LTFPTP commitments in each transmission study, including the following BC Hydro LTFPTP contracts:

- BC Hydro's LTFPTP transmission reservation of 230 MW on the BC-US path that includes BC Hydro's Load Forecast delivery of 123 MW to Seattle City Light under the Skagit River Treaty.
- BC Hydro (BCTC customer code BCPS) currently holds 249 MW in LTFPTP transmission reservations on the AB-BC path (TSR #71583712 and 71685250). These reservations have full roll-over rights. The current planning assumption is that BC Hydro will reduce the total generation east of the West of Selkirk (WoS) cut-plane up to the amount BC Hydro is importing on the AB-BC path as necessary to avoid congestion on the BCTC cut-planes west of Cranbrook (ie, WoS, WoAV[7] and ILM).

In addition, the Transmission Reliability Margins (TRMs) of the two WECC paths (65 MW for Path 1, AB-BC and 50 MW for Path 3, BC-US) are modeled in transmission planning studies.

E.2 FORTISBC POWER PURCHASE AGREEMENT (FBC PPA)

BC Hydro's Network Load includes a 200 MW delivery to FortisBC (FBC) under the Power Purchase Agreement (PPA). This 200 MW is delivered from BC Hydro's Network Resources to the Okanagan Point of Interconnection, POI, (170 MW) and the Princeton POI (30 MW).

E.3 COLUMBIA RIVER TREATY DOWN-STREAM BENEFITS

The Canadian Entitlement (**CE**) portion of the Columbia River Treaty Downstream Benefits are not assumed to be equivalent to dependable system capacity or as equivalent to Coastal RMR in transmission planning studies unless it is specified as such by BC Hydro. Except as specifically nominated by BC Hydro, the CE is not considered as a source of either dependable capacity or firm energy for the BRP or CRPs or as Coastal RMR.

However, since the CE is a source of firm energy and dependable capacity and because BC Hydro retains the CE as an "operational contingency" to meet firm load commitments for situations where planned generation or transmission additions are delayed, single-contingency (N-1) transmission capacity is provided to allow CE levels between zero and the full NITS-nominated CE amounts (eg, 1400 MW beyond 2013-Dec-31). This means that, when studying the ILM transmission requirements for the condition of maximum SI generation, maximum CE levels are modeled (ie, maximum inflows on the eastern tie at Nelway, NLY, that would increase ILM loading) with the NI generation reduced to achieve a load/resource balance.

[7] WoAV is the West of Ashton/Vaseux Lake cut-plane

E.4 ALCAN IMPORTS AND EXPORTS

BC Hydro specifies the Firm (equivalent to dependable generating capacity) and Non-Firm import and export limits to assume for the intertie with Alcan (ALN) for transmission planning studies. BC Hydro specifies the level of import from ALN to be assumed coincident with operation of the northern generating plants at the maximum aggregate dispatch level that BC Hydro specifies for defining System Normal (N-0) and Contingency (N-1) transmission requirements for the transmission system south of the Williston substation.