Wind Integration Cost and Limit

PURPOSE

To provide information on the wind integration cost and limit considered by BC Hydro in the Integrated Resource Plan (IRP).

OVERVIEW

Due to natural variations in wind speed, wind power generation is highly variable in the short-term timescales of seconds to minutes, resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. The natural variability in wind power generation also makes it difficult to forecast wind in the hour- to day-ahead timeframe, resulting in the need to set aside system flexibility in order to address the potential for wind generation to either under- or over-generate in this time frame. Both of these requirements for system reserves and flexibility have cost implications and place limits on the amount of wind that can be integrated into the electric system.

The implications of wind generation variability on the electric system have been studied separately from other resources for the following reasons:

- Solar and wave have similar characteristics as wind, but are not expected to be selected in portfolio analysis for economic reasons.
- The variability of run-of-river generation is largely contained within the monthly/seasonal timeframe, which is already addressed with IRP modeling tools (System Optimizer).

The wind integration cost was first introduced in the 2008 LTAP. Based on a preliminary analysis (Appendix F3 of the 2008 LTAP), a wind integration cost of $10/MWh was applied in the portfolio selection analysis. Since 2008, BC Hydro has conducted a more detailed wind integration study. Based on this more detailed study, BC Hydro is maintaining the $10/MWh wind integration cost, and is using 3000 MW as the upper limit of installed wind capacity that can be integrated into the BC Hydro electric system.

WIND INTEGRATION COST

What is the Wind Integration Cost?

The wind integration cost consists of two components:

- *Within-hour reserve capacity* - the variable nature of wind power requires an increased level of reserve capacity needed to maintain electrical system performance.
- *Day-ahead opportunity cost* – most power trading undertaken by BC Hydro/Powerex takes place in the day-ahead market. Due to potential errors in the day-ahead wind power forecasts, there is a need to reserve system flexibility to address potential swings in wind power output in the day-ahead timeframe, which in turn reduces the trade opportunities in the day-ahead market. The day-ahead opportunity cost is the estimated value of these foregone trade opportunities.

How is it Developed?

Wind Integration Study conducted by BC Hydro considers 12 wind integration scenarios consisting of:

- Two study years 2010/11 and 2020/21 which represent different system generation configurations (based on 2008 LTAP base case).

- Two wind diversity levels: economic dispatch and high diversity. For the economic dispatch case, wind farms were ranked and chosen according to their expected cost, whereas in the high diversity case, wind farms were chosen equally from all regions in BC. The economic dispatch case also represents low wind diversification.
- Three wind penetration levels: 15%, 25%, and 35%. The wind penetration level is defined as the percentage of installed wind capacity to peak load.

The wind power data as well as the wind power forecast data are based on the BC Hydro Wind Data Study (April 2009).

The within-hour reserve costs are determined using a statistical approach which calculates the reserve requirements at a confidence level of 3 standard deviations. The analysis is based on 10 years of concurrent 1-minute simulated wind power data and BC Hydro load data. The reserve requirements are valued at California Independent System Operator (CAISO) market prices, which have been confirmed with Pacific Northwest market data. The within-hour reserve costs are shown in Table 1 for the various wind integration scenarios.

Table 1 Within-Hour Reserve Cost

Within-Hour Reserve Cost	**2010/11 Study Year**	**2020/21 Study Year**
	$/MWh	**$/MWh**
Economic Dispatch, 15% (1,500 MW)	6.3	6.2
Economic Dispatch, 25% (2,500 MW)	7.4	7.3
Economic Dispatch, 35% (3,500 MW)	7.0	6.8
High Diversity, 15% (1,500 MW)	3.4	3.3
High Diversity, 25% (2,500 MW)	3.6	3.5
High Diversity, 35% (3,500 MW)	4.3	4.3

The day-ahead opportunity costs are determined using system optimization models.
The level of system flexibility required to manage the day-ahead wind forecast errors is determined at a confidence level of 3 standard deviations. Two strategies were allowed to obtain system flexibility:

- Method 1: Trade/generation schedule changes.
- Method 2: Spilling water, curtailing wind and trade/generation schedule changes.

The opportunity cost is determined for each method on a daily basis, and the most economic result for each day is used to determine the day-ahead opportunity cost. The day-ahead opportunity costs are shown in Table 2 for each of the wind integration scenarios.

The total wind integration costs, obtained by summing the within-hour reserve costs and the day-ahead opportunity costs for each wind integration scenario, are shown in Table 3. Generally speaking, the wind integration costs increase with increasing wind penetration levels, whereas geographic diversification has a decreasing effect. For the IRP, it is recommended that a wind integration cost of $10/MWh be used.

Table 2 Day-Ahead Opportunity Cost

Day-Ahead Opportunity Cost	**2010/11 Study Year**	**2020/21 Study Year**
	$/MWh	**$/MWh**
Economic Dispatch, 15% (1,500 MW)	4.3	6.5
Economic Dispatch, 25% (2,500 MW)	7.9	11.9
Economic Dispatch, 35% (3,500 MW)	6.3	9.6
High Diversity, 15% (1,500 MW)	2.0	2.8
High Diversity, 25% (2,500 MW)	2.7	3.8
High Diversity, 35% (3,500 MW)	3.2	4.2

Table 3 Total Wind Integration Cost

Total Wind Integration Cost *	**2010/11 Study Year**	**2020/21 Study Year**
	$/MWh	**$/MWh**
Economic Dispatch, 15% (1,500 MW)	10.8	12.8
Economic Dispatch, 25% (2,500 MW)	15.6	19.4
Economic Dispatch, 35% (3,500 MW)	13.6	16.6
High Diversity, 15% (1,500 MW)	5.4	6.0
High Diversity, 25% (2,500 MW)	6.4	7.3
High Diversity, 35% (3,500 MW)	7.6	8.5

*Includes a small additional cost component associated with wind variability.

Comparison to Other Jurisdictions

Wind integration studies have been conducted by a number of jurisdictions. The studies have – and continue to – become more detailed and sophisticated as each study builds on the modelling techniques from previous ones. Wind integration costs can differ considerably from utility to utility as they are strongly dependent on factors such as resource mix, wind penetration level, energy valuation, market structure, etc. Also, not all jurisdictions cover the same components of the wind integration cost. Table 4 shows the results from more recent studies for other jurisdictions. On a component by component basis, the BC Hydro costs are comparable to those from other jurisdictions.

Table 4 Wind Integration Costs for Other Jurisdictions

Utility/Study	Timeframe	Cost
Portland General Electric 2009 IPR Study	Total	\$11.75/MWh in \$2008 \$13.50/MWh in \$2014
Bonneville Power Administration in 2010 Rates	Within-Hour	\$5.89/MWh* + persistence deviation penalty
PacifiCorp 2008 Wind Integration Study	Within-Hour	\$7.51/MWh @ \$8 CO_2 cost \$9.40/MWh @ \$45 CO_2 cost
	Total	\$9.95/MWh @ \$8 CO_2 cost \$11.95/MWh @ \$45 CO_2 cost
Puget Sound Energy Within-Hour Load-Following Open Access Transmission Tariff (effective June 2010)	Within-Hour	\$12.33/MWh*

* A capacity factor of 30% was assumed to convert from \$/kW/month to \$/MWh.

How is the Wind Integration Cost Applied in the IRP?

The wind integration cost is an input to the portfolio selection analysis.

WIND INTEGRATION LIMIT

How is it Developed?

A preliminary analysis has been completed to determine the maximum amount of wind power that can be integrated into the current BC Hydro power system without impacting the reliability and security of the system. The analysis is based on the assumption that only dispatchable generation from automatic generation control (AGC) plants can be used to manage wind variability and ramps. Hence, the amount of wind integration is determined by the amount of available dispatchable generation from AGC plants, defined as the sum of the capacity of AGC plants minus the sum of AGC minimum generation limits.

The analysis was performed using actual hourly system operation data, including load, generation, max/min generation limits, outages and tie line schedules, for the period Oct 2007 to Sep 2008. The analysis assumes that there are no transmission constraints and that there is a market for the surplus wind energy. Actual wind data is not used in this analysis. The assumption is made that the intra-hour wind power fluctuations may range from minimum to maximum output (worst case scenario) and that the dispatchable resources have to be able to respond to these fluctuations.

Figure 1 shows the available dispatchable generation from AGC plants for the period Oct 2007 to Sep 2008. The system is most constrained during the freshet period when the available dispatchable AGC generation drops to approximately 3000 MW. Hence, it is recommended that 3000 MW be used as the wind integration limit. Further studies are underway to confirm the wind integration limit.

Figure 1 Available Dispatchable Generation from AGC Plants for the Period Oct 2007 to Sep 2008