2012 Integrated Resource Plan

BC hydro

Appendix

6E

Wind Integration Study Phase II

Table of Contents

List of Figures

List of Tables

1 Executive Summary

BC Hydro currently has 246 MW of wind generation operating on the electric system and an additional 534 MW of wind generation contracted through electric purchase agreements. Combined, this wind power generation represents a penetration level of approximately 7.8 per cent, as measured by installed wind capacity divided by peak load. BC Hydro expects wind to be offered into competitive power procurement processes in the future as well.

The unique characteristics of wind in comparison with other generation resources, including a high degree of variability and power output uncertainty over the timeframes of seconds to days, are well known and have been studied across the electricity industry. BC Hydro previously undertook an initial assessment of the impacts and costs associated with these characteristics. The result of this preliminary review was included in the 2008 Long-Term Acquisition Plan (**LTAP**) filing. This wind integration study builds upon this preliminary work using more robust wind data, analytical tools and further developed methodologies.

The specific objectives of this wind integration study are:

(i) Generate a set of hypothetical wind projects with corresponding synthetic wind data that can be used for analysis purposes by applying state of-the-art wind modeling technologies;

(ii) Determine the generation capacity requirements and costs of incremental operating reserves associated with wind power generation resources; and

(iii) Determine the impacts and costs of wind power generation resources on power trading activities in the day-head time frame.

The study examines the impacts and costs of integrating 15 per cent, 25 per cent and 35 per cent wind penetration levels. This represents approximately 1500 MW, 2500 MW and 3500 MW of installed wind capacity. Two diversity scenarios of how wind could come onto the electric system are also studied. The first scenario assumes that wind projects come onto the electric system in order of low to high resource cost. A high level estimate of the unit energy cost of the theoretical wind projects developed in the wind data study was used to rank the wind projects and economically dispatch them up to the wind penetration levels. This scenario is termed CAPEX, referring to the capital expansion model used in preparing this scenario. The second scenario involved choosing wind projects in appropriately equal proportions across the four regions of the province. The study years were F2011 and F2021.

Table 1 shows the average annual cost per megawatt hour of the operating reserve costs, the day-ahead opportunity costs, and the total wind integration costs associated with integrating wind power generation onto the electric system across the various study scenario combinations.

Table 1 Summary of Average Annual Operating Reserve and Day-Ahead Opportunity Costs ($2009)

Scenario Combination	Operating Reserve Costs ($/MWh)		Day Ahead Opportunity Costs ($/MWh)		Total Cost ($/MWh)	
	F2011	F2021	F2011	F2021	F2011	F2021
CAPEX 15% (1,500 MW)	6.49	6.30	4.30	6.45	10.79	12.75
CAPEX 25% (2,500 MW)	7.68	7.50	7.95	11.94	15.63	19.44
CAPEX 35% (3,500 MW)	7.27	6.97	6.31	9.57	13.58	16.54
High Diversity, 15% (1,500 MW)	3.39	3.24	2.00	2.78	5.39	6.02
High Diversity, 25% (2,500 MW)	3.65	3.51	2.70	3.75	6.35	7.26
High Diversity, 35% (3,500 MW)	4.45	4.31	3.19	4.21	7.64	8.52

The results of the study indicate that the impacts and costs associated with wind power generation on the electric system vary by wind penetration level, geographic diversity as well as by electric system and market conditions. The findings of this wind integration study are reasonably consistent with findings of other recent wind integration studies.

2 Introduction

BC Hydro acquires incremental power requirements through a competitive power acquisition process which results in various generation resource types being offered to the utility from the private sector. These generation resource types generally include wind, non-storage hydro and biomass.

BC Hydro currently has 246 MW of wind generation operating on the electric system and an additional 534 MW of wind generation contracted through electric purchase agreements. Combined, this wind power generation represents a wind penetration level of approximately 7.8 per cent, as measured by wind power generating capacity divided by peak load. BC Hydro expects wind to be offered into competitive power acquisition processes in the future as well.

Wind has some unique generation characteristics that include a high degree of variability and power output uncertainty over the timeframes of seconds to days. The implications of these characteristics must be understood by BC Hydro to help inform power acquisition evaluations of alternate generation resource types and for operational and long term planning processes.

The impact of wind power generation on electric systems is an area of interest in the electric utility industry. Many wind integration studies have been undertaken, and the knowledge base of the impacts of wind integration continues to grow. This knowledge base includes the understanding of how wind impacts electric systems and how wind impacts can be managed and mitigated. BC Hydro has reviewed many wind integration studies, utility practices and regulatory agency proposals in the area of wind integration in preparation for this wind integration study. Also, this wind integration study is the second effort by BC Hydro to study the impacts of wind integration. An initial and preliminary study of wind integration impacts was undertaken and filed as evidence in the LTAP. This wind integration study builds upon the findings from the initial study.

To date, BC Hydro has undertaken several review steps in the development of this wind integration study, including:

- A review of the wind integration literature, utility wind integration tariff development and regulatory agency proposals regarding wind integration practices;
- Internal review with system operations, power trading and generation resource management;
- Two review and input sessions with Clean Energy BC's wind group; and
- Preliminary discussions of the results with Clean Energy BC.

Wind power integration will continue to be examined by BC Hydro as operational experience is gained with wind power generation on the electric system and as study methodologies and issues continue to evolve in the electric industry.

3 Objectives

As found in the initial wind integration study, the main wind integration impacts are in the areas of:

(i) Operating reserves; and

(ii) Day-ahead (**DA**) power trading opportunity costs.

Operating reserves are generating capacity resources that are reserved to manage the electric system on a daily basis. These operating reserves are over and above contingency reserves which are held to address unplanned system outage events.

BC Hydro trades power with other entities in power markets across North America with a significant portion of power trading taking place at the California Mid-C exchange. A large portion of the power trading activity takes place in the DA timeframe. In the context of this study, DA power trading opportunity costs refer to the impacts that wind power generation on the BC Hydro electric system has on power trading opportunities in the DA time frame.

The purpose of this study is to re-examine these two main wind integration impacts areas using more robust wind data and more refined analytical tools and methodologies than used in the initial wind integration study. Specifically, the objectives of this wind integration study are:

(i) Generate a set of hypothetical wind projects with corresponding synthetic wind data that can be used for analysis purposes by applying state of the art wind modeling technologies;

(ii) Determine the generation capacity requirements and costs of incremental operating reserves associated with wind power generation resources; and

(iii) Determine the impacts and costs of wind power generation resources on power trading activities in the DA time frame.

4 Wind Integration Study Methodology

This section describes the methodologies used to study.

This study uses a portfolio of theoretical wind generation projects to model wind integration impacts. These theoretical wind projects were identified in the BC Hydro Wind Data Study (May 2009) which examined potential wind resources in the southern two thirds of the province. The report and a presentation associated with this wind data study can be found on the BC Hydro website. The wind data study was updated in September 2009. For the purpose of this wind integration study, only theoretical projects identified in the May 2009 study were considered as the associated data set contains more temporally resolved information than the data set from the September 2009 update study.

4.1 Study Scenarios

This wind integration study is undertaken at a time when there is still a relatively low level of wind power penetration on the BC Hydro electric system. In order to understand the future impacts of wind power generation on BC Hydro, the impacts of wind integration are examined across a number of scenarios that provide a range of possible ways that wind power generation resources may come online. The scenarios are not intended to be a forecast of how BC Hydro expects wind power generation to come onto the electric system, and hence should be viewed only as theoretical scenarios.

The two dimensions for how wind power generation may come onto the electric system are:

(i) **Wind penetration level** – This is a measure of the MW of wind generation resources on the electric system as a percentage of system peak load (approximately 10,000 MW); and

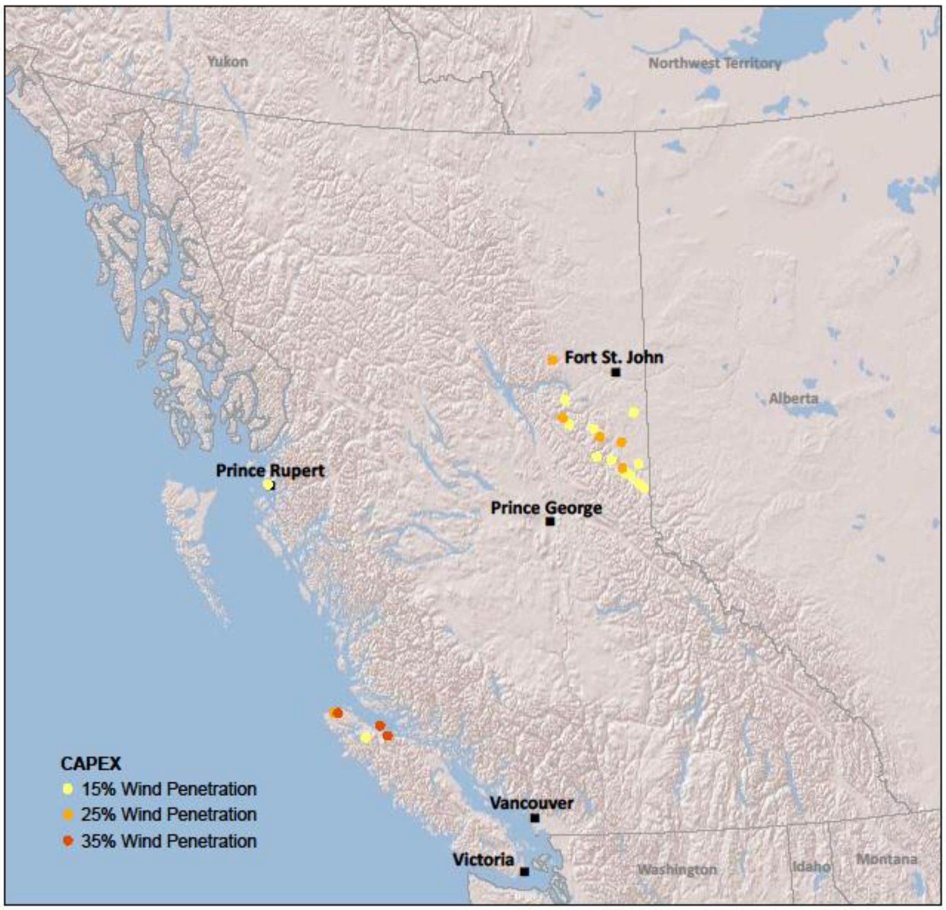
(ii) **Wind diversification level** – This refers to the geographic dispersion of the wind generation assets on the electric system.

Three wind penetration levels of 15 per cent, 25 per cent and 35 per cent are included in the study, representing installed wind capacities of approximately 1500 MW, 2500 MW and 3500 MW, respectively.

Two wind diversification levels are included in the study. The diversification scenarios are nested within the three penetration levels, to result in a total of six combined scenarios.

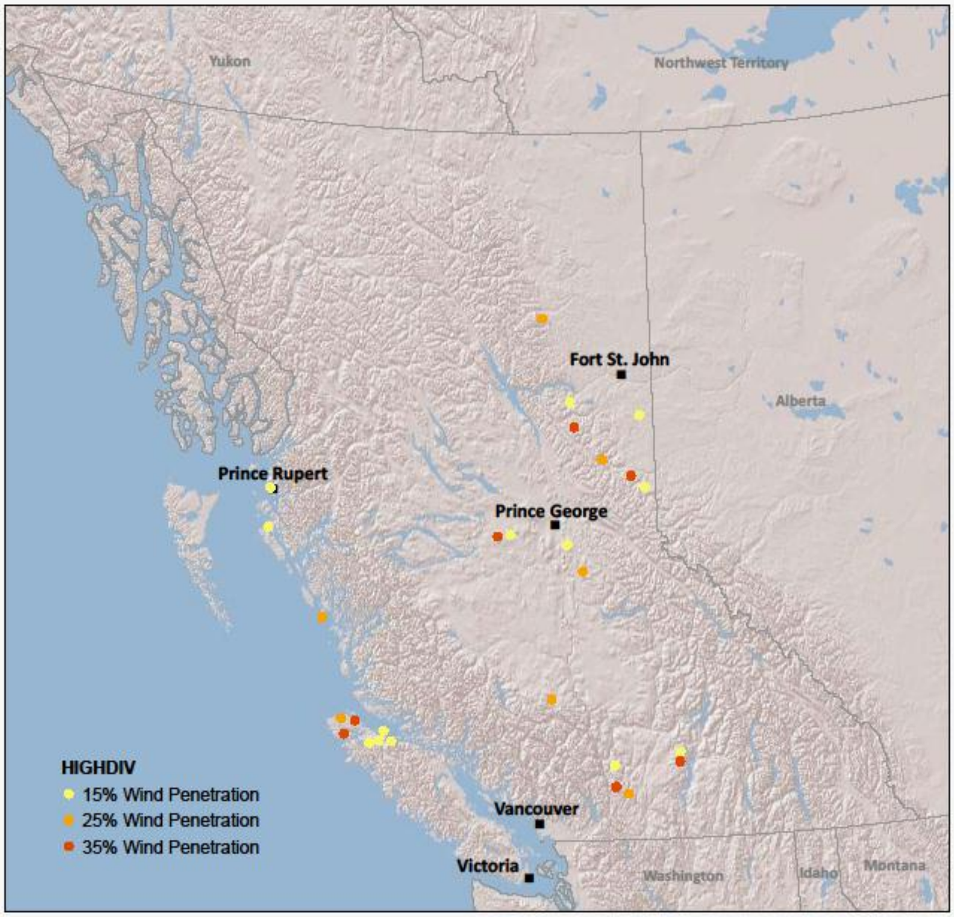
One diversification scenario addresses the potential geographic diversity of wind generation coming onto the system through a process of economic dispatch. The unit energy cost (**UEC**) of the theoretical wind generation projects was estimated at a high level and the wind projects were dispatched up to the wind penetration levels in the order of lowest to highest cost. These scenarios were created with CAPEX (also referred to as the System Optimizer model), which is a capital expansion model BC Hydro uses for economically dispatching generation resources over the planning horizon. As a result, these scenarios are referred to as CAPEX scenarios. Although not a direct intention of the CAPEX scenarios, they also represent a relatively low diversity level of wind generation resources. The locations of the resulting projects are shown in Figure 1.

Figure 1 Wind Project Locations in the CAPEX Scenarios



The second diversification scenario assumes that wind generation projects come onto the electric system in approximately equal proportions across the province in the Peace, Southern Interior, North Coast and Vancouver Island regions. The resulting scenarios represent high diversity cases and are referred to as the HIGHDIV scenarios. The locations of the resulting projects are shown in Figure 2.

Figure 2 Wind Project Locations in the HIGHDIV Scenarios



4.2 Study Years

The wind integration study years are fiscal F2011 (2010/2011) and F2021 (2020/2021). These years are chosen to provide results which represent near-term conditions and a mid-term planning perspective.

4.3 Methodology to Study Operating Reserves

In BC Hydro, there are three categories of operating capacity reserves:

- **Regulating reserves** include sufficient spinning reserve that is immediately responsive to automatic generation control (**AGC**) to provide sufficient regulating market to allow the control area to meet North American Electric Reliability Council (**NERC**) control performance criteria. Regulating reserves address the minute to minute time frame.
- **Load following reserves** are online generation equipment used to track changes in load in the 10 minute or more time frame; and
- **Imbalance reserves** cover differences in hour-ahead forecasts and the actual hourly averages for the hour.

In the study, a small amount of cost was found to be associated with sub-optimal within-the-day generation dispatch as a result of the variable nature of wind power. These costs are termed wind variability costs and given the small magnitude of these costs, they are included in the overall category of operating reserves for convenience.

The approach for determining the impact of wind power integration on operating reserves is to first identify the incremental reserve capacity requirements associated with bringing the wind projects included in each scenario onto the electric system. Second, the opportunity cost associated with carrying these incremental reserves is determined to understand the cost associated with the operating reserve impacts.

The incremental operating reserve requirements are determined using a statistical methodology. The requirements for regulation, load-following and imbalance reserves are determined for load only and for wind only, assuming sufficient reserves are carried to cover a three standard deviation confidence level (99.7 per cent). The reserves for load-net-wind are determined by combining the load only and wind only reserves using the root-sum-squares method. The incremental reserves for wind are then calculated by subtracting the load only reserves from the load-net-wind reserves. The reserve calculations are based on ten years of historical BC Hydro one-minute load data synchronized with ten years of simulated one-minute wind generation data. To determine the imbalance reserves, historical actual load forecasts from the Planning, Scheduling and Operations Shift Engineers (**PSOSE**) were obtained. For wind, the hour-ahead wind forecasts are based on persistence (i.e. $P_{current\ hour} = P_{previous\ hour}$).

Each of the reserves requirements are calculated as follows:

Regulating Reserves

- Calculate one-min averages of load and wind separately
- Calculate one-hour centered rolling averages of load and wind separately at each minute
- Subtract one-hour centered rolling average from 1-min average for each minute and for load and wind separately
- Use +/-three standard deviations of the data in step 3 to formulate the regulating reserve requirements
- Combine load and wind regulating reserve requirements using the sum-root-square method ($\square_{total} = (\square^2_{load} + \square^2_{wind})^{1/2}$)

Load Following Reserves

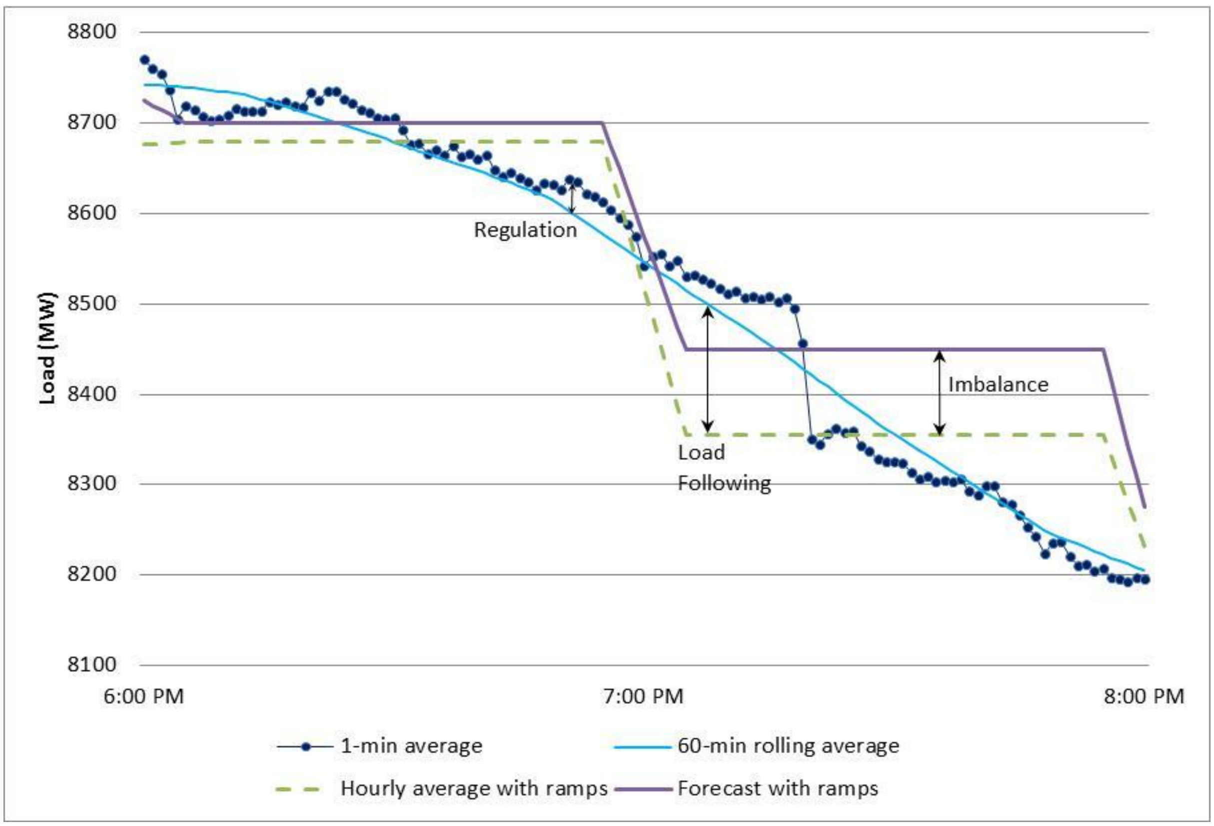
- For each minute, subtract the clock hour actual average from 1-hour centered rolling average for load and wind separately, including a 10-minute ramp (+/-5 minute) at the top of each hour
- Use +/-three standard deviations of the data in step 1 to formulate the load following reserve requirements
- Combine the load and wind load following reserve requirements using the sum-root-square method ($\square_{total} = (\square^2_{load} + \square^2_{wind})^{1/2}$)

Imbalance Reserves

- For each hour, subtract the clock hour actual average from the forecasted hourly average for load and wind separately
- Use +/-three standard deviations of the data in step 1 to formulate the imbalance reserve requirements
- Combine load and wind imbalance reserve requirements using the sum-root-square method ($\square_{total} = (\square^2_{load} + \square^2_{wind})^{1/2}$)

Figure 3 illustrates how the regulation, load following and imbalance reserves are determined.

Figure 3 Illustrative Schematic of the Basis for Calculating Regulation, Load Following and Imbalance Reserves



Once the incremental reserve requirements are determined, BC Hydro system modeling tools are used to determine the opportunity costs of holding these incremental operating reserves, based on an ancillary services market for the reserves.

Prices from the California Independent System Operator (**CAISO**) ancillary services market are used in this study as proxy values for an ancillary services market. A market for ancillary services exists as well in the Pacific Northwest. However, this market consists of less transparent bi-lateral transactions between buyers and sellers. The CAISO ancillary services market, on the other hand, is an open and transparent market. To ensure that the CAISO ancillary service pricing used in this study are reasonable, a comparison between the CAISO ancillary services market prices and existing contracts for ancillary services in the Pacific Northwest held by Powerex was undertaken. The findings confirm good agreement between these Pacific Northwest contract prices and the CAISO ancillary service market pricing.

4.4 Methodology to Study Day-Ahead Opportunity Costs

BC Hydro, through its power trading subsidiary, Powerex, actively participates in power trading markets. While there are many power trading timeframes in different markets, the dominant timeframes are the real time market and the DA market, with the DA market being significantly larger than the real time market. The real time market suffers from limited liquidity, which is less pronounced in the DA market.

Given the liquidity limitations of the real time market, BC Hydro does not anticipate relying on real time power trading markets to manage wind integration impacts to any significant degree. Therefore, the DA power trading market is the focus of this wind integration study. However, recognizing that some small level of real time market depth could be utilized to manage wind integration issues, the study assumes that 200 MW of the real time market could be used for this purpose.

Power trading takes place in the DA market in two main power trading time-steps: an eight hour light load hour (**LLH**) period, and a 16 hour heavy load hour (**HLH**) period.

Wind forecast uncertainty can have impacts on power trading activities in the DA market due to the fact that BC Hydro will not enter into DA power trading contracts without a high degree of certainty that it can deliver on these contracts. There are penalties associated with non-delivery and reputation risks that too punitive for BC Hydro to be exposed to in these markets. With wind power generation output being uncertain in the DA timeframe, a portion of the BC Hydro system flexibility may have to be withheld from the market in order to manage system operating requirements.

Wind forecast uncertainty can also be managed by spilling water and curtailing wind on the electric system. These strategies for managing wind forecast uncertainty are also included in the methodology to determine DA impacts of wind integration. Spilling water is limited to the Seven Mile plant given BC Hydro water spilling restrictions.

The approach to determining the impacts of wind power generation on the DA market includes the following steps:

(a) Understand the potential level of wind forecast error in the DA timeframe across the scenarios using the numeric weather prediction (**NWP**) wind forecasts from the wind data study;

(b) Determine how BC Hydro would optimally manage this uncertainty using power trading schedule changes, water spilling and wind curtailment activities; and

(c) Determine the opportunity cost of implementing the strategies to manage the wind forecast uncertainty.

For power trading schedule impacts, the opportunity cost is valued at energy market prices less transmission costs. For water spilling, the opportunity cost is valued at the BC Hydro water and storage value (**Rbch**). For wind curtailment, the opportunity cost is valued at Rbch plus the value of the Renewable Energy Credit (**REC**) that BC Hydro could have otherwise obtained from the wind power output.

Figure 4 and Figure 5 illustrate the framework used to determine the foregone market opportunities under DA import and export trading schedules conditions, respectively.

Figure 4 is an example for a HLH trading block where the DA market price is lower than the value of Rbch, resulting in an import schedule position. An expected hourly wind power output forecast is generated using a state-of-the-art wind power forecasting system. The average of the hourly wind forecast over the HLH period is used to prepare an import trading position for the DA HLH block trading schedule. This is 800 MW in Figure 4. Given the uncertainty in the wind power forecast, there is a potential for the wind power output to be higher than the expected forecast, and BC Hydro has to ensure that there is sufficient flexibility in the electric system to accommodate this potential upside swing in wind generation. To determine the required flexibility band (in MW), the maximum potential wind generation swing for any hour over the HLH trading block is first determined, based on a confidence level of 99.7 per cent (three standard deviations) in the DA wind power output forecasts. The maximum potential wind generation swing is capped by the installed wind capacity of 1500 MW in this example. An allowance is also incorporated to account for the fact that up to 200 MW of unplanned wind power output could be sold in the RT market without incurring significant negative pricing impact associated with a lack of liquidity in the RT market. The difference between this maximum potential wind generation, less 200 MW of RT market liquidity, and the average forecasted wind generation over the HLH period is the amount of hydro flexibility band that is to be reserved to accommodate the uncertainty in wind power output. In this example, it is 500 MW. The DA wind opportunity cost is determined by multiplying the magnitude of the block of the utility's foregone import by the difference between the market price (net transmission costs) and Rbch, divided by the actual amount of wind power generated over this period. So, for example, if the market price is $30/MWh, the Rbch is $60/MWh, and the transmission costs are $3/MWh, then the total DA wind opportunity cost would be (500MW * 16hr) * ($60/MWh – ($30/MWh - $3/MWh)) = $264,000. If the actual DA wind power output is less than the forecasted DA wind power output, no DA wind opportunity costs are incurred as load can be served with imports (up to 200 MW) or with BC Hydro's own generation.

Figure 4 Illustrative Example of the Basis for Determination of Reserves Required to Support a DA Import Trading Schedule

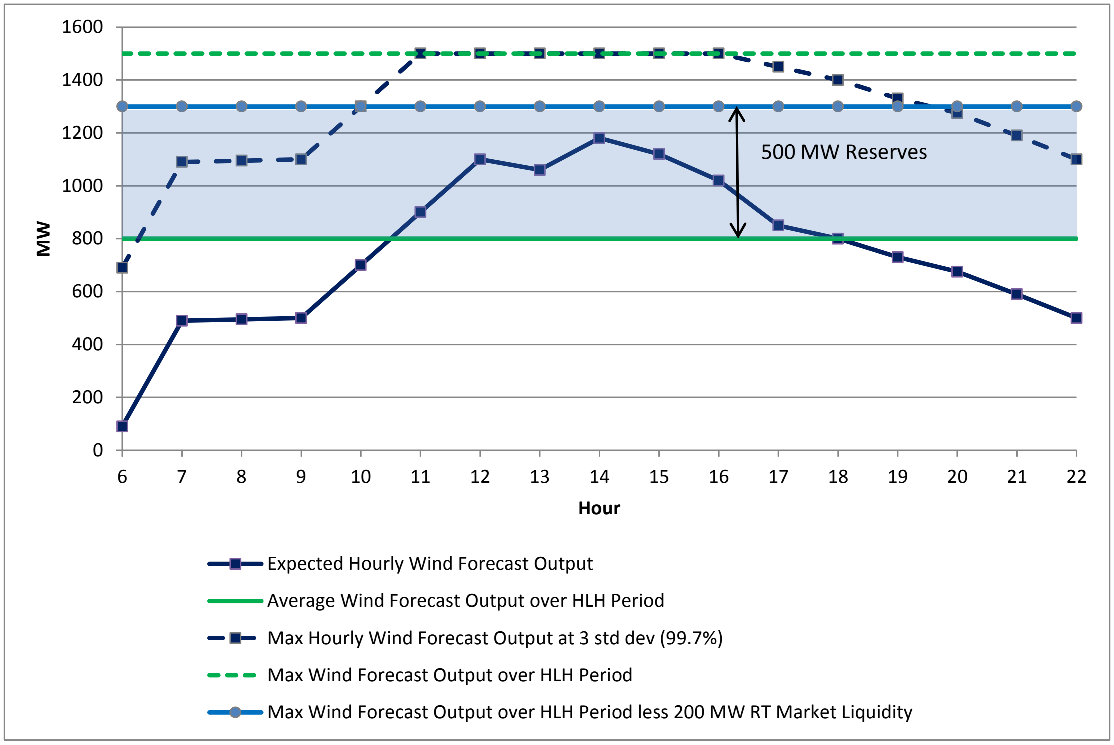
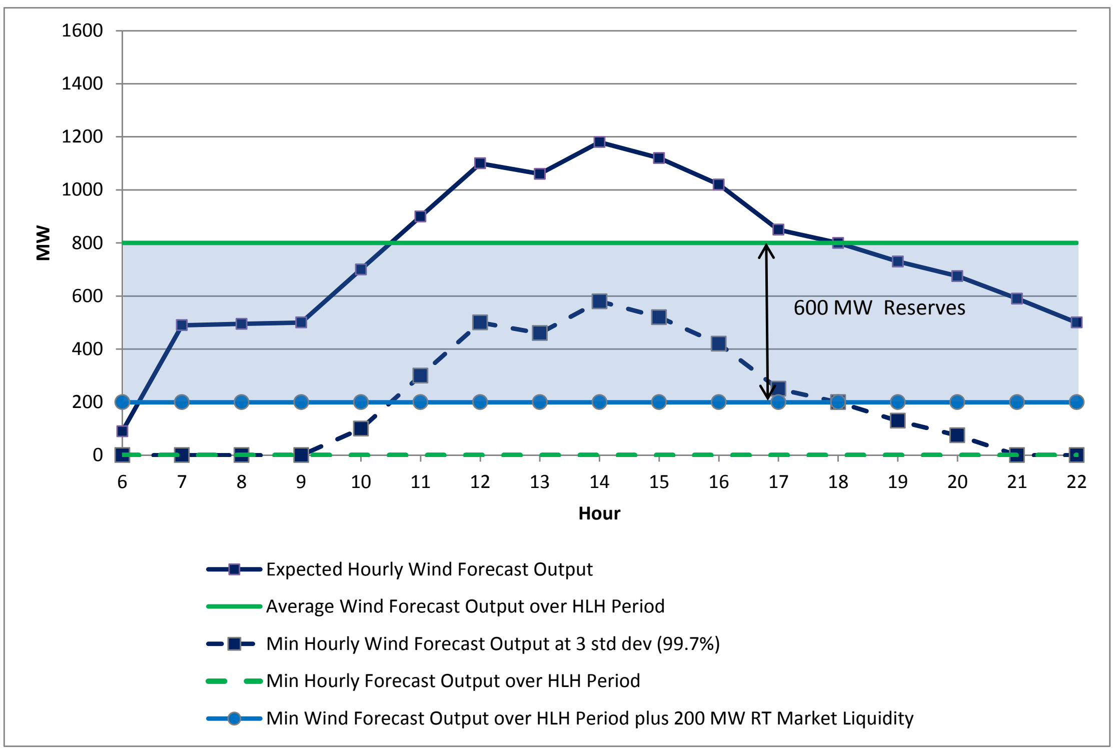


Figure 5 is an example for a HLH trading block whereby the DA market price is higher than Rbch, resulting in an export schedule position. In an export schedule position, there is a concern that the wind generation may be less than expected, and dependable hydropower resources must be reserved to back-stop the export trading schedule as a result of wind generation forecast uncertainty. Again, there is an opportunity cost associated with reserving these resources, which would have been used to exploit export opportunities. In Figure 5, the average expected wind power output forecast is 800 MW. The minimum expected wind generation output is 0 MW. An allowance for the fact that 200 MW of wind power that did not show up could be purchased in the RT market without incurring a liquidity driven price premium is included. The difference between the 0 MW of potential wind generation output plus the 200 MW of RT market liquidity, and the average forecasted wind power output is the flexibility band to be reserved to accommodate the wind forecast uncertainty, resulting in 600 MW of reserves. The WOC is determined by multiplying the magnitude of the block of the utility's foregone export by the difference between the market price (net transmission costs) and Rbch, divided by the actual amount of wind power generated over this period. If we assumed a market price of $50/MWh, a Rbch value of $30/MWh, and a transmission cost of $6/MWh, then the total DA wind integration cost for this example would be (600MW * 16hr) * (($50/MWh - $6/MWh) - $30/MWh) = $134,400. If the actual DA wind power output is more than the forecasted DA wind power output, no DA wind opportunity costs are incurred as the excess energy can be exported in the RT market (up to 200 MW) or stored in BC Hydro's reservoirs.

Figure 5 Illustrative Example of the Determination of Reserves Required to Support a DA Export Trading Schedule



In both the import and export examples above, DA wind opportunity costs are not incurred to the extent that the interties are constrained as there would otherwise not have been an opportunity to use the reserved hydro flexibility. Also, these generating reserves are over and above those required to manage within the day operating reserve requirements, avoiding double counting of reserves.

5 Modelling Tools, Data and Assumptions

This section details the modeling tools used to undertake this study as well as the data and key assumptions used in the modeling.

5.1 Tools

The main model used in the wind integration study is the Generation Optimization Model (**GOM**). Hydraulic boundary conditions for GOM are developed through the Hydro Simulation Model (**HYSIM**). Additionally, the Capital Expansion Model (**CAPEX**) was used for preparing wind project scenarios. These models are commonly used at BC Hydro for planning and operational purposes. A spreadsheet was used to calculate the incremental operating reserves.

5.1.1 GOM

GOM is used to determine the opportunity cost of the incremental operating reserves and the DA power trading opportunity costs.

GOM is a deterministic, linear optimization model that balances BC Hydro system loads and resources while maximizing the value of BC Hydro resources subject to operational constraints, including intertie limits on energy exports and imports with the U.S. and Alberta markets. For this study, an hourly time step is used in GOM to capture the variability in inflows, load, and prices within months and days. Inputs include the domestic load and available generating resources for a given year with their operating characteristics such as operating and flow constraints, unit efficiency curves, forebay and tailrace elevations, etc. In addition, the market price of electricity is incorporated into GOM to determine whether it is more economical to store or to draft optimized reservoirs to meet load requirements and trade in electricity markets.

GOM explicitly optimizes the operations of the five major BC Hydro hydroelectric plants which include GM Shrum (**GMS**), Peace Canyon (**PCN**), Mica (**MCA**), Revelstoke (**REV**) and Arrow Lakes Hydro (**ARD**). Of these facilities, GMS, MCA and REV are modeled to provide any type of reserve[1], whereas PCN and ARD are restricted to supplying only following and contingency reserves.

The remaining generation in the BC Hydro system that is not optimized is considered as fixed generation, and is represented in GOM with fixed monthly energy profiles. Fixed generation includes the Burrard Thermal Plant, Resource Smart Programs, smaller hydro generating facilities such as Seven Mile, Waneta and Kootenay Canal System, as well as energy from the Columbia River Treaty Non-Storage Agreement and energy from Independent Power Producers (**IPPs**).

For the purpose of this study, several modifications were made to GOM. Although GOM already includes and models operating and contingency reserves (ancillary services), regulating, load following and imbalance reserve requirements were added. In addition, the objective junction was modified to include the valuation of unused and available generating capacity, termed in this study as slack reserve capacity. The amount of slack reserve capacity, that is valued in GOM within each time step, is limited by both the physical amount of intertie space to the U.S.[2] as well as the portion of that available space that is already being used to import or export energy.

5.1.2 HYSIM

HYSIM is a tool that is used to provide boundary conditions to GOM in the form of monthly and year-end water level targets.

---

[1] The amount of up reserves available from GMS, MCA and REV has been adjusted to take into account current obligations for dynamic scheduling.

[2] Available intertie capacity to Alberta is not considered in the valuation of slack generation capacity since the intertie between B.C. and Alberta is currently not capable of handling reserves at the regulating time frame.

HYSIM is a monthly time step simulation model of the integrated BC Hydro electric generation system. It includes detailed hydraulic modelling of the hydro system as well as operating rules derived under separate Columbia River Treaty operating plans. For a given load and resource portfolio (including contracts), the model will determine the most economic dispatch of the generating system, subject to operating constraints, stream flow sequences and external market opportunities. The external markets are represented with both heavy load hour and light load hour import prices, export prices and tie-line limitations.

5.1.3 CAPEX

CAPEX was used in the study to select the wind projects included in the CAPEX scenarios.

CAPEX is a linear and mixed integer programming optimization model that is used to select an optimal resource expansion sequence for generation and transmission additions for a given set of input assumptions, e.g. load forecast, schedule of Demand Side Management (**DSM**) savings, natural gas and electricity prices and constraints such as transmission line limits and annual hydro generation profiles.

5.2 Data Assumptions

Data and assumptions used in the study for expected incremental energy, capacity and transmission resource requirements as well as anticipated system and market conditions for the study years are generally consistent with the LTAP[3]. The LTAP case used in this study is Medium Load with Moderate-Medium DSM (demand-side management).

For the operating reserve study, available intertie capacity to Alberta is not considered since the intertie between BC and Alberta is currently not capable of handling reserves at the regulating time frame.

Areas where additional data and assumptions were made are discussed below.

3 August 19, 2008 revision of the 2008 LTAP.

5.2.1 Energy Market Prices

The forecasted energy market prices were developed using EIA-forecasted gas prices with the same corresponding starting years for the source of market prices. Table 2 shows the resulting market energy prices for the study years F2011 and F2021. An hourly price profile was superimposed on the forecasted energy market prices to create a year-long schedule of hourly export and import prices at Mid-C. The import/export prices were adjusted for each water year to reflect the impact of stream flow conditions in the Pacific Northwest. For the hourly export price at the B.C.-U.S. border, wheeling and loss charges are subtracted from the Mid-C prices. For the hourly import price at the B.C.-U.S. border, wheeling and loss charges are added to the Mid-C prices. The prices at the B.C.-Alberta border are assumed to equal to the B.C.-U.S. prices multiplied by the U.S.-Canadian exchange rate.

Table 2 Annual Average Forecasted Energy Market Prices

	$CAN	$US
Reference Price	73.60	68.53
F2011	61.60	57.35
F2021	79.80	74.45

5.2.2 Ancillary Service Market Prices

Table 3 shows the average annual CAISO market clearing prices for three ancillary services used in the study for transmission node NP15.

Table 3 Average Ancillary Service Market Prices

Canadian Water Year	Down-Regulating Price ($/MWh)	Up-Regulating Price ($/MWh)	Spinning Price ($/MWh)
2002/03	17.27	16.44	5.94
2003/04	12.74	16.70	6.01
2004/05	13.73	19.40	9.71
2005/06	18.80	21.45	9.31
2006/07	10.51	14.58	4.86
2007/08	16.26	19.81	5.54

For this study, up-regulating and down-regulating reserve prices from CAISO are used to value regulating capacity from AGC-equipped generators, and spinning reserve prices from CAISO are used to value regulating capacity from non-AGC equipped generators as well as following and imbalance reserves. The 2007/2008 prices are used to value the incremental wind power generation operating reserve capacity as these prices represent the most current and complete ancillary service price data set available from CAISO.

5.2.3 Water Data

The inflows used in the GOM modelling runs are based on a ten-year period from October 1964 to September 1974. These ten water years are considered representative of the full sixty years of water record used in HYSYM, as they contain a range of water conditions including normal, dry and wet water years.

5.2.4 Load/Wind/Water Year Pairing

For the statistical analysis of the operating reserve requirements, the load data was synchronized with the wind data. For the GOM modelling for operating reserves, however, it was not possible to synchronize the wind data with the hydro inflow data. The period of August 1998 to July 2008 was chosen for the Wind Data Study because of available wind speed observations to verify modelling results. The update for the Pacific Northwest water inflow database, however, only extends to 1999, and hence it was not possible to synchronize the wind data years with the water years over a ten year period. In addition, the wind data set begins in August whereas the water year definition used by BC Hydro begins in October. As a result, only a nine-year period spanning October 1998 to September 2007 is used from the Wind Data Study, with the last year being repeated. Table 4 shows the water/wind year combinations used in the GOM modelling.

Table 4 Water/wind year combinations used in the GOM modelling

Water Year	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
Wind Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2006

To test the sensitivity of the GOM results to the particular water/wind year pairing used in this study, two additional runs were conducted. In the first sensitivity test, the wind years were allowed to vary while the water year was kept constant (average). In the second test, the water years were allowed to vary while the wind year was kept the same. The results of these sensitivity runs, shown in Table 5, show that the average reserve costs are very similar between the model runs using chronologically synchronized water/wind data and the two sensitivity runs.

Table 5 Percentage Difference in the Average Reserve Cost as a Function of Water/Wind Year Combination

Water/Wind Year Combination	Difference (%)
Chronologically synchronized	0
Water year held constant	-1
Wind year held constant	1

For the GOM modeling of the DA impacts, there was a restriction on wind data availability due to the fact that the wind data study only provided three years of NWP based forecasts corresponding to F2006, F2007 and F2008. Therefore, these three years of wind forecast data were paired with the three water inflow years of F1969, F1970 and F1974, representing normal, dry and wet water conditions, respectively.

6 Results

This section describes the results for the operating reserve requirements, the operating reserve costs, and the DA power trading opportunity costs.

6.1 Operating Reserve Requirements

Table 6 shows the annual average incremental regulation, load following and imbalance reserve requirements as a result of the wind power generation associated with the six scenarios. The imbalance reserves make up the major component of wind reserves, accounting for approximately 80 per cent of the total incremental wind reserves. Regulation and load following reserves are of similar magnitudes in the CAPEX scenario. For the HIGHDIV scenarios, regulation reserves are slightly higher than the load following reserves.

Table 6 Average Up and Down Incremental Regulation, Load Following and Imbalance Reserves by Wind Scenario

Wind Scenario	Up Reserves (MW)			Down Reserves (MW)		
	Reg.	Fol.	Imb.	Reg.	Fol.	Imb.
CAPEX15	16.1	12.0	126.6	-14.6	-12.5	-83.4
CAPEX25	28.0	27.8	247.5	-25.4	-28.7	-183.1
CAPEX35	34.3	33.9	298.1	-31.5	-34.9	-210.0
HIGHDIV15	11.4	4.1	47.5	-9.3	-4.2	-27.3
HIGHDIV25	17.4	8.5	98.6	-15.3	-8.6	-55.7
HIGHDIV35	26.4	15.4	166.0	-22.4	-15.6	-94.3

Figure 6 and Figure 7 show the monthly variation of the total incremental up and down reserves for each diversity and penetration level scenario combination, respectively. The incremental wind reserves are slightly higher during the summer months when the wind variability is high, and the load reserve requirements are low.

Figure 6 Monthly Variation of Total Incremental Wind Up Reserves.

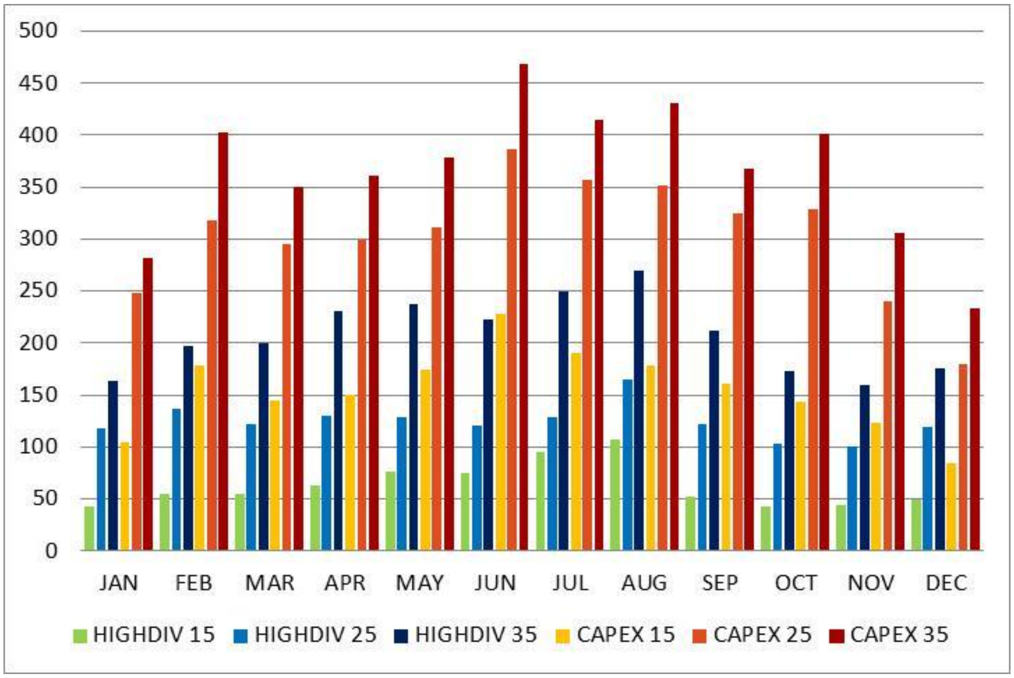
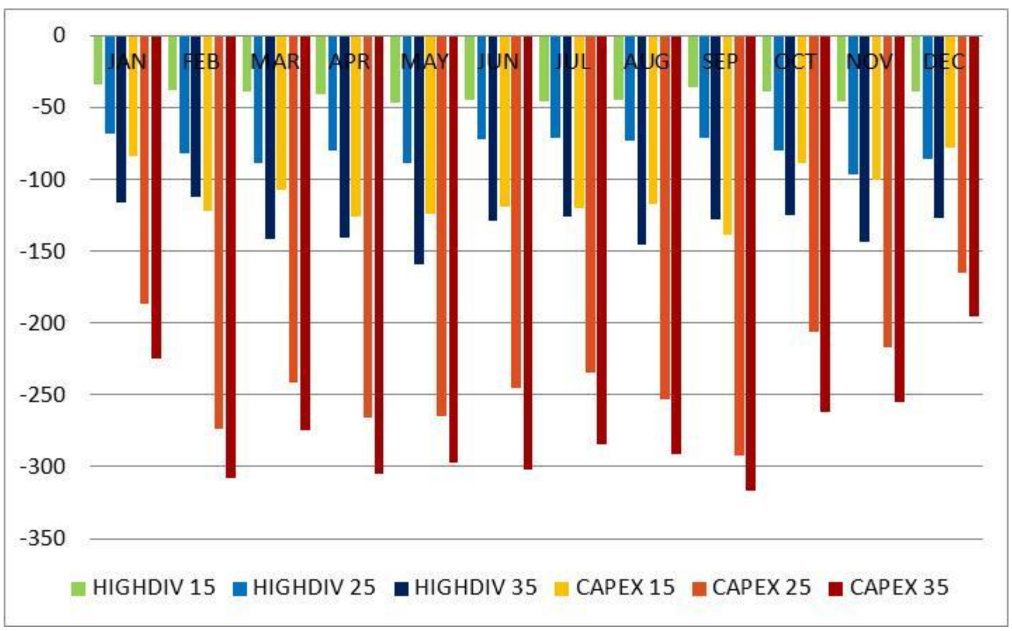


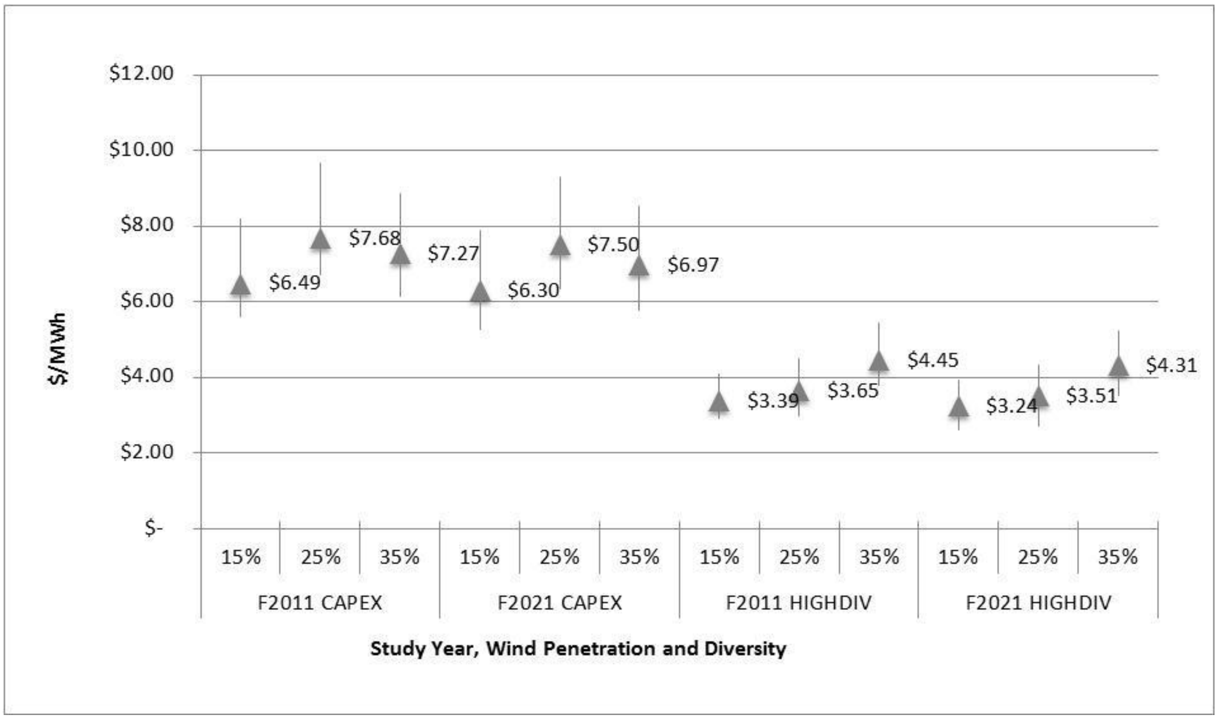
Figure 7 Monthly Variation of Total Incremental Wind Down Reserves



6.2 Operating Reserve Costs

The operating reserve costs associated with the six modeled scenarios are shown in Figure 8. For each scenario combination, the range of the operating reserve cost associated with the ten water/wind year combinations is represented by the vertical line and the arrow shows the average operating reserve cost for these ten water/wind year combinations.

Figure 8 Operating Reserve Costs ($2009)

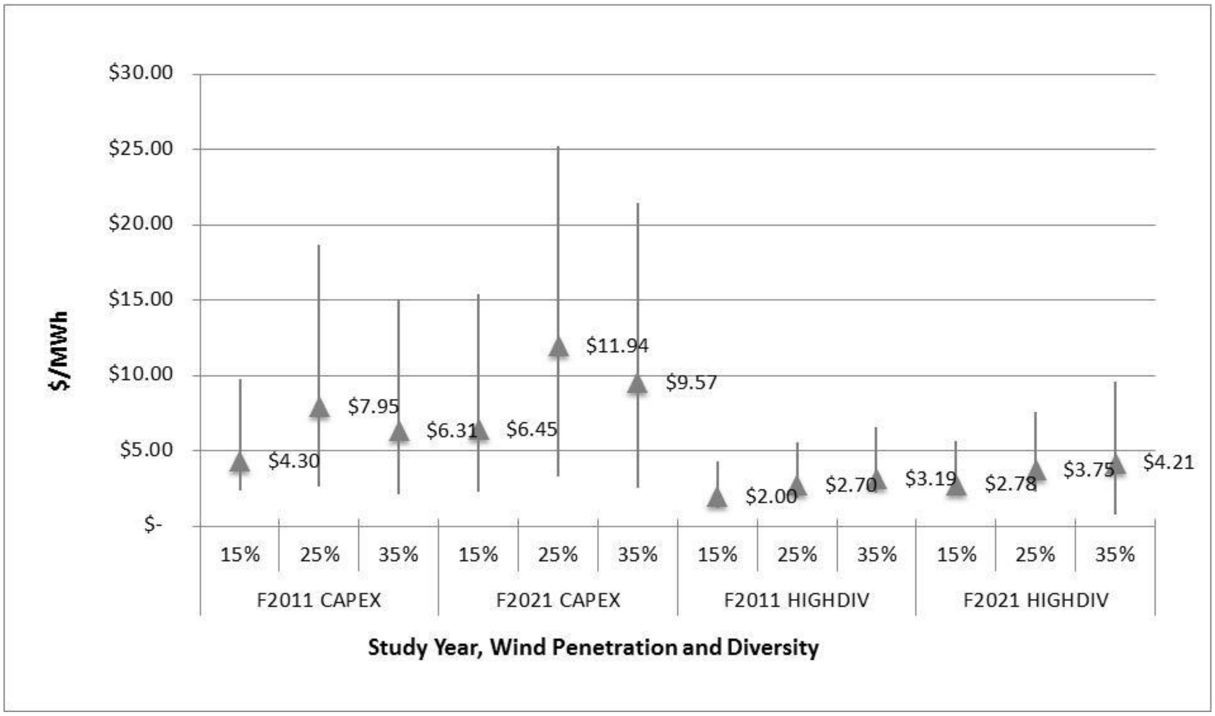


Through the process of calculating the operating reserves, a cost associated with the only the variability of wind, separate from the cost of the incremental reserves was detected. This cost was small and ranged from -$0.09/MWh to $0.30/MWh in the annual timeframe. Figure 8 includes both operating reserve and variability costs.

6.3 Day-Ahead Opportunity Costs

The DA opportunity costs associated with the six modeled scenarios are shown in Figure 9.

Figure 9 Day-Ahead Opportunity Costs ($2009)



The min/max range is based on the three water years that were modelled. The average values are weighted averages (0.5 for normal, 0.2 for dry, and 0.3 for wet water years). The maximum opportunity costs occur during the dry year. The minimum values are typically associated with the wet years, with the exception of some of the high diversity cases, where the minimum cost values are associated with the normal year.

6.4 Comparison to Other Jurisdictions

A review of wind integration costs found in recent studies from other jurisdictions is shown in Table 7.

Table 7 Jurisdictional Review of Wind Integration Costs

Utility/Study	Timeframe	Findings
Puget Sound Energy Within-Hour Load Following OATT Tariff effective June 2010	Within-Hour	\$2.70 kW-month @ 30% CF = \$12.33/MWh
PacifiCorp 2008 Wind Integration Study	Within-Hour	\$7.51/MWh @ \$8 CO2 cost \$9.40/MWh @ \$45 CO2 cost
	Hour-Ahead	\$2.17/MWh
	Day-Ahead	\$0.28/MWh
	TOTAL	\$9.95/MWh @ \$8 CO2 cost \$11.85/MWh @ \$45 CO2 cost
Portland General Electric 2009 IRP Study	TOTAL	\$11.75 in \$2008 \$13.50 in \$2014
Bonneville Power Administration 2010 Rates	Within Hour	Regulating Reserves \$0.05/kW/mo Following Reserves \$0.26/kW/mo Imbalance Reserves \$0.98/kW/mo Total \$1.29/kW/mo @ 30% CF = \$5.89/MWh + Wind generators are subject to a persistence deviation penalty to address ramping forecast inaccuracies.

7 Summary and Conclusions

This wind integration study provides further understanding of the impacts and costs associated with integrating wind onto the BC Hydro electric system.

Although the BC Hydro electric system has highly flexibly generation resources, wind power integration drives the need for incremental operating reserves which present an incremental cost to BC Hydro.

Uncertainties associated with wind power generation in the DA time frame result in an inability to commit as much of the system flexibility to the DA power market as would be possible without wind power generation on the system. Therefore, there is an opportunity costs associated with wind power generation on the electric system due to foregone power trading opportunities.

The impacts and costs associated with wind power generation on the electric system vary by wind penetration level, geographic diversity, as well as by electric system and market conditions.

The findings of this wind integration study are reasonably consistent with findings in other recent wind integration studies.