VALUE OF PUMPED-Storage HYDRO FOR WIND POWER INTEGRATION IN THE BRITISH COLUMBIA HYDROELECTRIC SYSTEM

by

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ABSTRACT

In the next few years, the province of British Columbia will experience the installation of significant amounts of wind power as part of BC Hydro calls for clean renewable energy resources. The inherent variability and uncertainty of wind power will impact the operation of the BC Hydro system. If the system loses some of its flexibility in the process of integrating more wind power, there are costs that need to be assessed and recognized. Of particular interest are the costs associated with incremental wind reserves to manage wind variability and the cost associated with foregoing day-ahead market opportunities due to the wind forecast error. Pumped-storage hydro systems have been proposed as a good technology to complement wind generation due to their ability to manage wind energy imbalances over time. This research investigated the feasibility of expanding an existing hydropower system by installing a pumped-storage hydro system to mitigate the impacts of integrating wind in a large scale hydro system. This study proposed the installation of an additional pump station, equipped with automatic generation control capabilities.

Two optimization models were developed to assess the benefits of the pumped-storage hydro system and the impacts of wind integration: A long-term mixed integer optimization, and a short-term stochastic linear optimization models to simulate BC Hydro short-term operations considering different load and wind stochastic scenarios. Both models are an extension of the BC Hydro Generalized Optimization Model (GOM), which is a deterministic linear optimization model that has been used to assess many capital investments and water use planning studies for the BC Hydro system. The model proposed in this research included a stochastic extension of GOM.

Optimization runs of the BC Hydro’s hourly system operation for one year, with and without the pumped-storage hydro system were carried out and their outcomes were compared to estimate the overall benefits of the pump-storage system. The results indicated that there are benefits of installing a pumped-storage hydro system in the BC Hydro system to manage and to reduce wind power integration impacts. The benefits increased as more wind power is installed in the BC Hydro system.
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LIST OF ACRONYMS

AGC – Automatic generation control
ALCAN – Rio Tinto Alcan project
ARD – Arrow Lakes Hydro
ARMA – Autoregressive Moving Average
ASCE – American Society of Civil Engineers
BC – British Columbia
BCTC – British Columbia Transmission Corporation
BPA – Bonneville Power Administration
CAISO – California Independent System Operator
CO₂ – Carbon dioxide
DA – Day-ahead
DOE – U.S. Department of Energy
DSM – Demand Side Management
EPRI – Electric Power Research Institute
ERCOT – Electric Reliability Council of Texas
EU – European Union
EWEA – European Wind Energy Association
FERC – US Federal Energy Regulatory Commission
GE – General Electric
GMS – GM Shrum Generating Station
GOM – BC Hydro Generalized Optimization Model
GWh – Gigawatt-hour
ha – hectares
HK – Flow to power ratio
HYSIM – Hydrological Simulation Model
IPP – Independent Power Producer
IRR – Internal rate of return
ISO – Independent System Operator
LFE – Load forecast error
LOLP – Loss of load probability
LTAP – BC Hydro Long Term Acquisition Plan
MCA – Mica Generating Station
Mid-C – Mid-Columbia
MVA – Megavolt ampere
MW – Megawatt
MWh – Megawatt-hour
NERC – North American Electric Reliability Corporation
NPV – Net present value
NWP – Numerical Weather Prediction
OM – Operation and Maintenance
PCN – Peace Canyon Generating Station

REV – Revelstoke

RSP – Resource Smart Projects

RT – Real-time

STOM – BC Hydro Short Term Optimization Model

U.S. – United States of America

yr – year

WFE – Wind forecast error

WILMAR – Wind Power Integration in Liberalised Electricity Markets
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1 INTRODUCTION

1.1 Overview
Currently, the possibility of climate change associated with the intensive use of fossil fuels has alerted the public and governments about the risks and consequences of a carbon dependent economy. The issue of climate change is becoming a major element in the new energy policies around the world. In North America, these energy policies have been the key driver for renewable energy expansion in the last five years. For example, the Canadian government has set an overall goal of a 20% reduction in greenhouse gas emissions by 2020, using 2006 targets as baseline, with specific energy policies, greenhouse gas emission and renewable energy targets for each province (NERC, 2009).

Among all the renewable energy sources currently available, wind power has become one of the fastest growing energy resources in the world, due to the significant cost reduction and the relatively lower environmental impact of this technology. From 1997 to 2007, the installed wind power capacity grew 10 times, and it is expected that this rate will remain steady during the next few years (EWEA, 2009). Nowadays, production costs of wind turbines range from US$85 to US$75 per megawatt-hour (MWh), and current experiences indicate that this cost range is expected to decline to between US$77 and US$60 per MWh by 2015 (EWEA, 2009B).

Unlike conventional energy generation facilities, the output of wind farms varies according to the availability of the primary fuel (i.e. the wind) that cannot be stored. This output is very intermittent due to the stochastic (i.e. unpredictable) nature of wind. Therefore, wind power is classified as a variable generation resource because it exhibits greater variability and uncertainty than conventional generation resources (such as thermal, nuclear, large hydro) in all planning time horizons.

The variability and uncertainty of wind power produces financial, technical and reliability impacts for electrical utilities and power users when wind power (and other variable generation) is integrated in a conventional electric system. To accommodate higher penetration levels of wind power, changes will be required to traditional methods used by system planners and operators in order to maintain an acceptable level of reliability of the bulk power system on an
ongoing basis. New tools and infrastructure should be implemented as well to mitigate the impact of wind power integration.

It is very important to assess the magnitude and consequences of wind integration impacts in a large scale electric power system. This information is necessary, first, to allow for a reliable and efficient integration of wind power, and second, to ensure that market mechanism and electricity tariffs are fair and non-discriminatory for wind power. To deal with these issues, several wind integration studies have been prepared around the world. These studies have provided a relatively good insight about the range of wind integration impacts. However, any action to be taken by the industry or policy makers regarding the regulation of variable generation is still a topic that requires the attention of all participants. Recently, the US Federal Energy Regulatory Commission (FERC) issued a notice of inquiry seeking comments from interested parties on the issues related to variable energy generation resources (FERC, 2010).

Some of the wind integration study reports have proposed energy storage as an alternative to mitigate wind power integration impacts. Energy storage could provide back-up production capacity in low wind and high load periods and could absorb wind power in high wind and low load periods, thus, providing additional flexibility to the power system as a whole (Wilmar, 2005).

Among existing energy storage technologies, pumped–storage hydro facilities has been considered to be an attractive alternative for load balancing and energy storage. It can provide ancillary services at high ramp rates and it could also provide benefits from intraday energy prices variation by releasing energy at highly demand periods and buying energy at off-peak periods. These features of pumped–storage hydro facilities may be of great help for the integration of intermittent energy sources such as wind power on providing balancing and storage services to these facilities when needed.

The attractiveness of pumped-storage hydro to accommodate variable generation has already resulted in building several of these projects around the world, particularly in Europe and North America. In Europe, approximately 7,400 megawatt (MW) of new pumped-storage hydro projects have been proposed, with an investment cost of approximately € 6 billion (Deane et al., 2010). A significant number of these projects correspond to expansion of existent hydropower
projects in order to maximize the use of existent hydropower infrastructure facilities. In North America, the energy sector has also showed special interest for pumped-storage hydro in the last few years. Last December, FERC’s Chairman, Jon Wellinghoff, testified before the U.S. Senate Committee on Energy & Natural Resources on the regulatory and technical issues related to the integration of electricity technology. He said that “...Energy storage offers the ability to balance the variability of some renewable resources.” He also pointed out that the most-used electricity storage technology is pumped-storage hydro. Currently the North American Electric Reliability Corporation (NERC) has issued permits for more than 27,000 MW of pumped-storage hydro in the U.S (Hydro Review, 2010), and it is expected that this trend will continue in the next few years.

Pumped-storage hydro systems, however, may present a number of problems such as the environmental damage caused by reservoirs and the difficulty of finding topographically suitable sites with sufficient water capacity to make the installation of such systems profitable (Bueno, 2005). However, the current trend of new pumped-storage hydro development is to install these facilities in already existing hydropower infrastructure or to install closed loop systems with underground reservoirs. Both options can avoid most of the problems mentioned above. In particular, pumped-storage hydro is well suited for installed cascade reservoirs systems which are close enough, and therefore, that they can be easily connected by installation of additional water conveyance systems.

1.2 The BC Hydro System and Wind Integration

BC Hydro is the biggest electric power utility in British Columbia (BC), serving about 94% of its population. BC Hydro operates 33 generating facilities in several regions of this Province. Almost 90% of the electricity is produced by hydropower plants located throughout the Province with a total generating capacity of about 10,700 MW and an average annual energy production of about 48,000 gigawatt-hour (GWh). The most important of these facilities are located on the Peace River (two plants, 29% of total energy production) and the Columbia River (three plants, 28% of total energy production). These plants are also used to regulate and balance the electric system. The rest of the hydropower plants, together with two thermal generating facilities,
energy provided by Independent Power Producers (IPP) plants and imports/exports provide the balance of energy and demand in BC.

BC is currently a net importer of electricity (5% of the province’s electricity demand is met with imports). The BC Energy Plan, which was unveiled in 2007, set a goal to procure sufficient electrical energy resources to make up BC annual energy deficit by 2026. This goal has led to several calls for powers to acquire green renewable energy. The 2006 Open Call for Power awarded 38 contracts totalling 7,000 gigawatt-hour per year (GWh/yr). Recently, the BC Hydro Clean Power Call released in 2008 aimed to acquire 5,000 GWh/yr of green renewable energy by 2016. In total, these two Calls for Power have already awarded contracts for 854MW of wind power (equivalent to approximately 8% of the total BC Hydro system capacity). There are plans to include more wind power into the province energy portfolio in the next 20 years.

Under the current energy development scenario, BC could experience the installation of important number of wind turbines. In order to prepare the necessary infrastructure and/or operation plans to manage this variable generation, BC Hydro is currently carrying out a Wind Integration Study to assess the impacts and cost to generation and system operation for a number of significant wind power penetration levels (BC Hydro, 2008). Specifically, this study aims to answer the following questions:

- What are the transmission system requirements to integrate wind resources?
- What capability the current power system has to integrate intermittent wind resources from a system operations perspective?
- How does wind energy impact the system flexibility to supply load and to undertake trade?
- What are the associated costs of integrating wind energy in a large hydro system?
- What forecasting standards and equipment and what wind farm design methods can be used to reduce the integration impacts and costs?

While BC Hydro has a flexible large hydro-based generation system (approximately 95% hydro generation) that can be used to manage the wind power variability, the total system flexibility is limited and its value is optimized in the markets. As a result, if the system loses some of its flexibility due to the integration of wind power, there are costs associated with losing these resources that need to be recognized. The first part of the BC Hydro Wind Integration Study
identified that adding wind resources will require BC Hydro to carry appropriate additional capacity reserves to compensate for sudden fluctuations in wind power, with an added cost for the system (BC Hydro, 2008).

Another main concern that should be addressed in detail in the current phase of this Wind Integration Study is how wind integration will impact the day-ahead scheduling process and day-ahead energy transactions in neighbouring markets. Some market trade opportunities could be lost if the BC Hydro system has to reserve some of its flexibility to cover for the inherent uncertainty of wind power. To assess these scheduling impacts caused by wind integration, a simulation of the day-ahead scheduling and energy trade decision making process could be prepared using stochastic modes to represent the inherent uncertainty of wind power.

To provide additional reliability and flexibility for the BC Hydro system under significant wind power penetration, it is believed that an energy storage system can mitigate wind power integration impacts. Pumped-storage hydro systems can be an attractive addition to the current BC Hydro system, because:

- It can be used to store energy and provide additional load when significant wind over-generation occurs (i.e. when the actual wind is greater than the forecasted wind), thus, avoiding wind curtailment or to generate more power when wind under-generation occurs, thus, avoiding dispatch of expensive resources.
- It can help to balance day-ahead wind generation uncertainty.
- It can provide additional capacity reserves to compensate for wind power variability.
- It can avoid transmission bottlenecks.

At this time, one of the most attractive sites to install a pumped-storage hydro system is at the Mica – Revelstocke reservoir system. BC Hydro has already proposed to install two additional 500 MW generating units in the existing powerhouse at Mica Generating Station (BC Hydro, 2010). To construct the pumped-storage system at Mica, a pump station can be installed near the Mica powerhouse. According to the information provided by BC Hydro engineers, the installation of this pump station is technically feasible. An added benefit of this pumped-storage hydro system is that it can also help to capture freshet inflows that flow into the Revelstocke
reservoir that are otherwise forced to generate power in the freshet period when the system load and market prices are low or are otherwise spilled if the system is at minimum generation.

1.3 Goals and Objectives

The goal of this research is to investigate what are the advantages of a pumped-storage hydro system for mitigating the impacts of increased wind integration in the BC electric system. Specific objectives to be reached are:

1. To identify and estimate the impacts of wind power integration in the BC electric system, with an emphasis on incremental capacity reserves for wind and day-ahead scheduling impacts.
2. To develop a stochastic optimization model to assess the impact of wind integration on the scheduling process for day-ahead and real-time energy market transactions. The model should also be capable of integrating and assessing the operation of a pumped-storage hydro facility in the BC Hydro system.
3. To estimate the potential benefits of installing a pumped-storage hydro system in the Mica – Revelstoke reservoir system under different wind power development scenarios.
4. To investigate the financial and economic feasibility of building a pumped-storage hydro system in the BC Hydro system.

1.4 Organization of the Thesis

This thesis is organized into six chapters. This chapter provides an introduction to the research and its objectives. Chapter 2 provides a literature review which includes a summary of typical wind power integration impacts, a description of pumped-storage hydro facilities and a review of different optimization models for electric systems with wind power and pumped-storage hydro. Chapter 3 details the methodology used to estimate the cost and benefits of wind power and pumped-storage hydro, including the formulation used to develop the optimization model for the operation of the BC Hydro system. Chapter 4 provides the data and assumptions used in this research. Chapter 5 presents the results of this research. Finally, Chapter 6 provides conclusions and recommendations for future research work.
2 LITERATURE REVIEW

This literature review provides the reader with the background information pertaining to the approach and tools used in the subsequent analysis and application. In the first section the challenges of integrating large-scale wind power facilities in the electric system are reviewed to provide context. The second section introduces pumped-storage hydro facilities and presents their potential benefits for large-scale wind power integration. The third and fourth sections familiarize the reader with linear programming and its application for modelling and assessing the integration of wind power and pumped-storage hydro facilities in electric systems.

2.1 Large-Scale Wind Power Integration

Wind power generation has become one of the fastest growing energy resources in the world, due to public demand for clean and renewable energy sources and significant cost reduction of this technology. Because of this rapid growth rate, electric utilities with significant wind potential in their service territories have performed studies about the technical and economic impact of incorporating wind farms into their systems. These studies have provided a wealth of information about the expected impact of wind farms in the electric system operation and planning, as well as valuable insights of possible strategies to manage this growing source of power generation.

2.1.1 Description of typical wind integration impacts

A summary of wind integration impacts over the electric system and the evolution of wind integration studies in the last years can be found in the work of Ackermann (2005), Holtinnen (2008), Smith et al. (2007) and De Meo et al. (2007). Table 2.1 shows a categorization of these wind integration impacts. An overview of these impacts is described in the following sections.

System stability and voltage management

This issue is related to voltage and power control. Concern existed in the past regarding large-scale wind integration because wind turbines can create reactive power and voltage control issues. However, modern wind turbines designs are compatible with the design and operation of existing power systems (Smith et al., 2007). For system stability reasons, operation and control
properties similar to conventional power plants will be required for wind plants at some stage depending on penetration and power system robustness (Holtinnen, 2008). There is already technology available that allows wind farms to provide voltage management and reactive reserve (Ackermann, 2005).

<table>
<thead>
<tr>
<th>Type of effect</th>
<th>Impacted element</th>
<th>Extent</th>
<th>Timescale</th>
<th>Possible impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short term</td>
<td>System (grid) stability and voltage management</td>
<td>Local or whole system</td>
<td>Seconds / minutes</td>
<td>Wind farms can exhibit similar stability behaviour different than equivalent conventional synchronous generation</td>
</tr>
<tr>
<td>Short term</td>
<td>Regulation and following reserves</td>
<td>Whole system</td>
<td>Several minutes to an hour</td>
<td>Wind power can contribute to an increase for these reserves</td>
</tr>
<tr>
<td>Short term</td>
<td>Scheduling and commitment of thermal and hydro power units</td>
<td>Whole system</td>
<td>1 h – 7 days</td>
<td>Impact depends on how the system is operated, wind distribution and the use of short-term wind forecasting</td>
</tr>
<tr>
<td>Short term</td>
<td>Transmission and distribution efficiency</td>
<td>Local or whole system</td>
<td>1 – 24 h</td>
<td>Depending on wind penetration level, wind farms may create additional investment cost or benefits.</td>
</tr>
<tr>
<td>Short term</td>
<td>Discarded energy</td>
<td>Whole system</td>
<td>hours</td>
<td>Wind power can exceed during, certain times, the amount of energy the transmission system can absorb.</td>
</tr>
<tr>
<td>Long term</td>
<td>System reliability</td>
<td>Whole system</td>
<td>Years</td>
<td>Wind power can contribute to power system adequacy (in terms of capacity credit).</td>
</tr>
</tbody>
</table>

**Table 2.1: Summary of Impacts of Wind Power Integration**

Source: Adapted from Ackermann (2005).

**Regulation and following reserves**

An electric system requires regulating and load following reserves to manage minute-to-minute and hour-to-hour fluctuation of load demand respectively. The amount of reserves to be kept is proportional to the required level of reliability for the electric system. Usually this amount is expressed as two to three times the standard deviation of the load distribution, which covers more than 99% of the variation of the Gaussian distribution (Ackermann, 2005).
The variability and uncertainty of wind results from the fact that its electric generation fluctuates every minute and every hour as it capacity depends on wind speed. Part of this fluctuation is not possible to predict or forecast accurate, so additional regulating and following reserves for wind power are needed. Both the allocation and the use of these reserves result in additional costs, because reserves (or ancillary services) are provided by conventional power plants, which have to forgo part of their production to provide these service reserves. This increase in reserves has been estimated mainly using statistical methods combining the variability of wind power and load (Holtinnen, 2008).

Research in this area indicates that, the larger the electric system area and the larger the load, the larger the amount of wind power that can be incorporated in the system without increasing reserves (Ackermann, 2005).

Because wind and load are generally uncorrelated in short time scales, the regulation impact of wind has been found to be modest. For example, Smith et al. (2007) indicated that in two wind integration studies performed in the United States, the addition of 1500 MW and 3300 MW of wind, corresponding to 15% and 10% of peak system load respectively, increased the regulating reserve requirements in 8 MW and 36 MW.

In the case of following reserves, the net increase in variability is less than the isolated variability of the wind alone. With high wind penetrations, an increment of ramp requirements can also occur and enough following reserves must be maintained in the system to manage such ramps.

**Scheduling and unit commitment**

Usually, the scheduling and unit commitment of generation units to ensure that forecasted load is balanced with reserves are usually prepared in advance (from one day to one week). During this process, the electric system operator seeks to optimize the total generation minimizing its cost. Large amounts of intermittent wind power generation can cause efficiency losses in conventional generation, because in real time thermal and hydro plants would have to be rescheduled and be operated below their economical optimum level (due to additional start-ups, shutdowns, part load operation) to manage the difference between the forecasted wind generation and the actual (real) wind generation. This difference is known as the wind forecast error. Wind forecast error could potentially affect transactions in day-ahead, hour-ahead and real time electric markets.
prices would likely fluctuate according to the wind forecast error, sometimes resulting in increases in imbalance costs (Ackermann, 2005).

When assessing wind power integration impacts over scheduling and unit commitment time frames, the unpredicted part of the wind power variation should be combined with any other unpredicted variations encountered by the power system, such as unpredicted variations in load (Holtinnen, 2008). The magnitude of this impact depends on several factors such as: the balancing region size or extent, timescale of system operation (how updated forecasts are taken into account), initial load variations and how concentrated/distributed wind power is across the balancing area.

The quality of the wind forecast technique in use is a significant factor to control this impact, because high prediction errors of wind power can result in high imbalance costs. Smith et al. (2007) indicates that the state-of-the-art forecasting systems can provide 80% of the benefits that would result from a perfect forecast.

**Transmission and distribution efficiency**
Wind power can have significant impacts on the power flow in a network. It may change the power flow direction, reduce or increase power losses and exacerbate bottleneck situations. Wind power can either decrease or increase the transmission and distribution losses, depending on where it is situated in relation to the load, and the correlation between wind power production and load consumption (Holtinnen, 2008). In some cases, transmission grid reinforcement become necessary to maintain the system transmission adequacy. This is the case in Europe, where the large-scale integration of wind power is expected to require a substantial increase in transmission capacity. This can be achieved by network optimisation and other operation measures, but the construction of new lines will also be necessary (EWEA, 2009).

**Discarded energy**
If wind power production exceeds the amount that can be safely absorbed, while still maintaining adequate reserves and dynamic control of the system, then a part of the wind energy production may have to be curtailed (Ackermann, 2005). Whether such a measure is taken depends strongly on the operational strategy of the power system. Wind curtailment can affect the carbon credits revenues of wind producers, because less wind generation would involve less abatement of CO₂
produced by coal-fired plants, diesel-fired plants or gas-fired plants, therefore, resulting in less carbon credit revenues.

**System reliability**

Electric systems must be able to serve load demand with a sufficiently low probability of failure. Dimensioning the system for system adequacy usually involves estimations of the loss of load probability (LOLP), which is calculated by accounting for the firm generation capacity available in peak load situations. Wind power can contribute to certain level of capacity, or capacity credit, depending of the magnitude of wind power installed.

A proper assessment of wind power’s aggregate capacity credit in the relevant peak load situations will then be required. Aggregating large balancing areas has a positive impact on the capacity credit of wind power as well. Wind power contribution to capacity can be close to the average power produced by wind at times of peak load, when the penetration of wind power is not high (Holtinnen, 2008). The capacity value of wind power does not increase as wind penetration increases. According with Ackermann (2005), the capacity value tends towards a constant value, which ranges between 15%-24% of the installed wind power capacity.

### 2.1.2 Financial cost of wind power integration

Regarding the cost of the impacts previously mentioned, Holtinnen (2008) indicates that at wind penetrations of up to 20% of gross demand (energy), the system operating cost increases by about 1 – 4 €/MWh (approximately 1.35 – 5.50 US$/MWh). This is about 10% of the wholesale value of the wind energy. Similar results are found in the work of Smith et al. (2007), who focus more in wind integration studies carried out in the United States. A summary table with the total operating cost impacts of wind integration for different utilities in the United States is shown in Table 2.2.

Regarding the value of wind power, Holtinnen et al. (2008) found that there is a benefit when wind power is added to electric systems, because it reduces the total operating costs and carbon emissions as wind replaces fossil fuels. Wind power normally replaces fuels in the generation units with the highest operating costs. There is also the added value for wind power producers of
obtaining carbon credits for wind power generation. The CO₂ abatement of wind energy is usually considered to be 800-900 gCO₂-kWh⁻¹ (Ackermann, 2005).

<table>
<thead>
<tr>
<th>Date</th>
<th>Study</th>
<th>Wind Capacity Penetration (%)</th>
<th>Regulation Cost (US$/MWh)</th>
<th>Following Cost (US$/MWh)</th>
<th>Unit Commitment Cost (US$/MWh)</th>
<th>Gas Supply Cost (US$/MWh)</th>
<th>Total Operating Cost Impact (US$/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>May03</td>
<td>Xcel-UWIG</td>
<td>3.5</td>
<td>0.00</td>
<td>0.41</td>
<td>1.44</td>
<td>na</td>
<td>1.85</td>
</tr>
<tr>
<td>Sep04</td>
<td>Xcel-MNDOC</td>
<td>15.0</td>
<td>0.23</td>
<td>na</td>
<td>4.37</td>
<td>na</td>
<td>4.60</td>
</tr>
<tr>
<td>Jun06</td>
<td>CA RPS</td>
<td>4.0</td>
<td>0.45</td>
<td>na</td>
<td>na</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>Jun03</td>
<td>We Energies</td>
<td>4.0</td>
<td>1.12</td>
<td>0.09</td>
<td>0.69</td>
<td>na</td>
<td>1.90</td>
</tr>
<tr>
<td>Jun03</td>
<td>We Energies</td>
<td>29.0</td>
<td>1.02</td>
<td>0.15</td>
<td>1.75</td>
<td>na</td>
<td>2.92</td>
</tr>
<tr>
<td>May05</td>
<td>PacifiCorp</td>
<td>20.0</td>
<td>0.00</td>
<td>1.60</td>
<td>3.00</td>
<td>na</td>
<td>4.60</td>
</tr>
<tr>
<td>Apr06</td>
<td>Xcel-PSCo</td>
<td>10.0</td>
<td>0.20</td>
<td>na</td>
<td>2.26</td>
<td>1.26</td>
<td>3.72</td>
</tr>
<tr>
<td>Apr06</td>
<td>Xcel-PSCo</td>
<td>15.0</td>
<td>0.20</td>
<td>na</td>
<td>3.32</td>
<td>1.45</td>
<td>4.97</td>
</tr>
</tbody>
</table>

Table 2.2: Wind Integration Costs in the United States

Source: Adapted from Smith et al. (2007).
Note: “na” means not assigned.

2.2 Wind Integration Impacts for Hydropower Utilities

Two crucial differences between thermal power based utilities and hydropower based utilities are the possibility of storing energy and the possibility of ramping up and down generation in very short periods of time at a lower cost than thermal systems. Storing allows the electric utility to respond to rapidly emerging development in market prices. That is, when prices are high, water is released and energy is produced and sold immediately, whereas when prices are low, the water is held back and the energy is saved for future disposal at higher prices (Fleten et al., 2007). This flexibility means that the impacts caused by wind power integration over the bidding strategies of hydropower utilities are extremely relevant.
Therefore, as hydropower resources are operated to maximize their market value, the cost of the wind integration impacts is not simply related to the production-cost of the hydropower utility. Rather, “opportunity costs” defined by market prices should be carefully analyzed and considered in the assessment of these wind integration impacts (De Meo et al., 2007).

Hydropower plants are considered to be one of the best technologies to provide ancillary services (reserves) due their high level of operational flexibility. If incremental reserves are needed to manage wind variability, then hydropower plants will have to forgo part of their capacity to hold reserves on stand-by at a cost. This cost will be higher at peak load periods when energy production is more valuable. The loss of revenue of not being able to sell ancillary services to other utilities must be also accounted for this cost.

As was mentioned in Section 2.1.1, during the scheduling and unit commitment process, the electric system operator seeks to optimize the value of resources in the short-term. To do that, system operators prepare a generation schedule to operate the system at its most efficient pattern for the next day(s). In the case of hydro-dominated utilities, system operators should also consider the trade-off between present benefits obtained from energy market transactions, and the potential expected long-term value of the water resources (Shawwash et al., 2000). Therefore, when hydropower plants are balancing deviations from the expected wind generation in real-time, some preferred market transactions or reservoirs storage are foregone. This can result in an added cost for the utility that can be classified as the scheduling cost of wind integration. The scheduling cost of wind integration is related to existing market structure where a hydro-dominated electric utility operates and to the water value of the hydropower plant that will provide the balancing services. These costs are also proportional to the magnitude of the day-ahead wind forecast error.

Wind integration costs for hydro-dominated utilities have been analyzed for various electric systems in Sweden, the U.S. Northwest, Canada, and many other countries. In Sweden, the analysis carried out by Söder (1994) included the estimation of losses in water storage as a function of the changes in the hydro system operation for different wind scenarios. In U.S. Northwest, the impacts of wind integration have been studied by different utilities separately (e.g. Avista, Pacific Corp, Bonneville Power Administration), who formulated an action plan for wind integration that identified hydro resources as the principle source of operating reserves and
balancing services to integrate wind in the Northwest (Northwest Wind Integration Action Plan, 2007). In Canada, Manitoba Hydro proposed a methodology that relied on running a hydroelectric scheduling optimization model for different cases of wind penetration to estimate the wind integration cost attributed to incremental reserves, purchases in real-time export market, water spills and/or lost export opportunities during low flow periods (Molinsky, 2009). In the case of British Columbia, BC Hydro proposed a wind integration methodology that was based on analyzing incremental reserves costs and opportunity costs of having to forgo low price imports/high price exports due to the need to provide sufficient system flexibility requirements to manage day-ahead wind forecast error (BC Hydro, 2008).

2.3 Benefits of Energy Storage Systems for Wind Power Integration

Several reports that were prepared by different electric utilities have proposed energy storage as an alternative to mitigate wind power integration costs. Conclusions from the European Wind Power Integration in Liberalised Electricity Markets (WILMAR) project indicate: “…The development and introduction of cost effective, low loss electricity storage would be beneficial for the power system. The electricity storage could provide back-up production capacity in low wind/high load periods and absorb power in high wind/low load periods, and could provide flexibility to the power system as a whole” (Wilmar, 2005).

The North American Reliability Corporation (NERC) also indicates that: “... a well known operating challenge with variable generation is the possibility of over-generation during light load conditions when conventional generators that must be kept on line are dispatched to their minimum operating level …Under these circumstances, the power system operator must have the ability to limit or reduce the output of variable generation, in order to maintain system reliability during over-generation periods. For example, to mitigate the potential for over-generation conditions in response to this circumstance, balancing areas may consider trading frequency responsive reserves during light load conditions or explore the use of batteries, flywheels, loads, etc. to provide this capability” (NERC, 2009).
The California Independent System Operator (CAISO) also indicates that storage facilities can provide a number of benefits that will help with the integration of large amounts of wind and solar renewable power (CAISO, 2007). The benefits identified in this report are:

- Save off peak energy production from wind generation and delivering the energy during on-peak periods. If the wholesale price differential between off-peak and on-peak periods is large, then the storage technology can be economically justified.
- Provide ancillary services such as regulation and contingency reserves and reactive power for voltage support.
- Add significant flexibility to the operation of the power grid as they can respond in a few seconds to system control fluctuations to absorb energy, ramp up/down or add load to the system, and can also help in mitigating wind over-generation or under-generation problems.
- Mitigates large wind ramps. Storage systems can quickly supply energy to the system when needed and help with the mitigation of large load and/or wind generation energy ramps.

The EPRI-DOE Handbook Supplement “Energy Storage for Grid Connected Wind Generation Applications” (EPRI-DOE, 2004) indicates that one way to minimize risk and increase wind value is to operate an energy-storage device in parallel with the wind turbine. Appropriate operation of the resulting hybrid system will potentially decrease the trading risk by allowing firm power levels to be achieved. Such operational capability potentially allows the wind generator to take advantage of price fluctuations and to avoid penalties for deviating from firm schedules.

A summary including the main benefits of energy storage systems for the integration of wind power is provided:

**Firm Wind Energy and Capacity Credits**

An intrinsic value of energy storage applied to wind power resources is the ability to firm and shape that portion delivered through the energy storage system. Hence this system can gain the dispatchable benefits associated with firm energy prices, plus a capacity credit (where this credit is available), versus the otherwise non-firm energy prices.
Energy Arbitrage (Wind Energy Imbalance and/or Shift Energy)
Wind energy sold into bulk electricity markets often receives lower-than-average energy value, because errors in forecasting wind can lead to substantial energy imbalance penalties. Energy storage allows for shifting wind output over time, and then it mitigates wind forecasting errors or delivers energy at a time when electricity prices are higher. This provides an energy arbitrage value benefits to the wind storage system, which increase when there is daily volatility in energy market prices. Higher peak energy prices increase storage benefits, whereas higher off-peak energy prices decrease storage benefits.

Ancillary Services Value
Energy storage systems can participate in ancillary services market. To do so, the system should be continually on-line and made available to respond quickly and reliably to system control functions and signals to provide these services. Several different types of storage batteries as well as hydro pumps and turbines can provide frequency regulation (EPRI-DOE, 2004). Energy storage can also provide spinning reserves and contingency reserves.

Figure 2.1 shows the annual total operating benefits of storage systems for three Independent System Operators (ISOs) in the US. These results reflect the prevailing and varying prices in each market. It can be seen that regulation provides the dominant benefit in PJM and NY-ISO. For ISO-NE, the regulation benefit is much smaller than in the other markets, but it is still substantial. The benefit available by providing reserves (spinning and contingency) was noticeable only in the ISO-NE case. As might be expected, the sensitivity of ancillary values to changing market prices was found to be high. Overall, ancillary service markets for energy storage offer excellent value-added potential. However, financing of energy storage system solely based on ancillary services is unlikely to be financially due to potential market price volatility for these services. However, as the markets for these services mature it is expected that these types of services will play an important role in the feasibility of these systems.
Wind Curtailment and Transmission Investment
Curtailment of wind generation and related spillage of wind resources in constrained power systems can be avoided when energy storage is applied. The condition that causes wind generation to be curtailed during certain periods may be related to time of day or contingency limits on the transmission or could be related to the required margins for load following and regulating generation. The value provided by energy storage in these cases is the capture of wind energy that would otherwise be lost, as well as any related green power tax credits. Closely related to curtailment avoidance is the value associated with substation or transmission investment deferral. Here, energy storage allows scheduling of the power to periods when transmission assets are not heavily loaded, thus improving transmission utilization and deferring the need for upgrades or expansions.

2.4 Characteristics of Pumped-Storage Hydro Systems
Pumped-storage hydro systems are hydropower plants that store pumped water in a reservoir. These artificial inflows are usually obtained by utilizing energy available in the electric system during periods of low electric demand. The fundamental concept behind this type of facilities is
very simple. Energy is stored as hydraulic potential energy by pumping water from a low-level into a higher level reservoir. When energy generation is required, the water is returned to the lower reservoirs through turbines which drive electric power generation.

Pumped-storage hydro is the most used bulk *electricity storage system* around the world. Table 2.3 summarizes its development worldwide up to 1996. With the significant development of variable generation in recent years, the development of pumped-storage hydro regained significant interest. Currently NERC issued permits for more than 27,000 MW of pumped-storage hydro in the US (Hydro Review, 2010). Within the European Union (EU) there is currently approximately 7,400 MW of new pumped-storage hydro development proposed, which constitutes a 20% increase in of pumped-storage hydro capacity in the EU (Deane et al., 2010).

<table>
<thead>
<tr>
<th>Country</th>
<th>Total Pumped Storage Capacity in Operation GW</th>
<th>Total Electric Generating Capacity GW</th>
<th>Pumped-storage as a Percentage of Total Capacity %</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA</td>
<td>21.9</td>
<td>994.5</td>
<td>2.2</td>
</tr>
<tr>
<td>Japan</td>
<td>24.6</td>
<td>241.2</td>
<td>10.2</td>
</tr>
<tr>
<td>Germany</td>
<td>4.9</td>
<td>125.6</td>
<td>3.9</td>
</tr>
<tr>
<td>France</td>
<td>4.3</td>
<td>116.2</td>
<td>3.7</td>
</tr>
<tr>
<td>Italy</td>
<td>4.0</td>
<td>88.9</td>
<td>4.5</td>
</tr>
<tr>
<td>UK</td>
<td>2.7</td>
<td>81.8</td>
<td>3.3</td>
</tr>
<tr>
<td>Spain</td>
<td>5.3</td>
<td>80.3</td>
<td>6.6</td>
</tr>
<tr>
<td>Switzerland</td>
<td>1.7</td>
<td>19.5</td>
<td>8.7</td>
</tr>
<tr>
<td>Austria</td>
<td>3.6</td>
<td>19.3</td>
<td>18.7</td>
</tr>
<tr>
<td>Australia</td>
<td>2.3</td>
<td>49.0</td>
<td>4.7</td>
</tr>
<tr>
<td>Portugal</td>
<td>1.0</td>
<td>13.9</td>
<td>7.2</td>
</tr>
<tr>
<td>Greece</td>
<td>0.7</td>
<td>13.5</td>
<td>5.2</td>
</tr>
<tr>
<td>Slovak Republic</td>
<td>0.9</td>
<td>8.0</td>
<td>11.2</td>
</tr>
<tr>
<td>Ireland</td>
<td>0.3</td>
<td>6.7</td>
<td>4.5</td>
</tr>
</tbody>
</table>

*Table 2.3: Pumped-Storage Hydro Capacity Development Worldwide, in Gigawatt (GW)*

(Source: Adapted from Deane et al., 2010).
2.4.1 Description of pumped-storage hydro facilities

Pumped-storage hydro is usually comprised by the following components:

- An upper reservoir for storing energy.
- Water pipes or penstocks.
- Pumps and turbines (it can be also reversible turbines).
- Motors and generators.
- Switchyard and transmission lines.
- A lower reservoir to discharge the water used for generation or to capture water used for pumping.

Figure 2.2 shows a schematic of the Racoon Mountain pumped-storage hydro plant in the Tennessee Valley, USA. This plant has four reversible turbines units with capacity to produce 1,582 MW during periods of high electric demands. The upper reservoir of this project has a surface area of only 326 ha.

Figure 2.2: Pumped-Storage Hydro Facility Diagram
(Source: Adapted from Tennessee Valley Authority website. http://www.tva.com/power/hydro.htm).
The arrangement of the components mentioned above is flexible and site-dependent. Designs considerations for these projects usually follow the same ones proposed for a conventional storage hydroelectric project. Moreover, a pumped-storage hydro project can be combined with a conventional storage hydroelectric project. This is the case of many of the new pumped-storage hydro development in Europe, where a significant number of projects proposed are either extension to existing hydropower projects, or repowering of existing pumped-storage hydro systems (Deane et al., 2010).

An important difference, however, with a typical hydropower project is given by the relative increment in power capacity ratings, pumping heads and rotational speed of reversible turbines. These characteristics require that these hydraulic units have to be set at considerable depths below the minimum tailwater level in order to avoid cavitation problems (Ter-Gazarian, 1994). Furthermore, the massive concrete structures required to comply with these characteristics have made it more cost-effective for the entire water-to-wire system (i.e. reversible turbines, generators, motors and switchyards) to be built underground.

New trends in pumped-storage hydro development favour the construction of a closed loop system (or modular pumped-storage systems), meaning that two artificial reservoir are built to avoid environmental impacts on existing water bodies. The development of new construction techniques to prepare cost-effective underground lower reservoirs has also helped in the development of closed loop systems.

A good example of a closed loop pumped-storage hydro system is the Aquabank concept of the IPP Riverbank Power, which plans to use this concept to build 1,000 MW of pumped-storage hydro plants across North America. Each of these facilities calls for excavation of a half dozen caverns to form an underground reservoir and for the upper reservoir it can adapt to various topographical features depending on their location. Typically, the powerhouse and underground reservoir will be excavated at a depth of approximate 600 m, and will cover 10-12 times that of the surface structures. The power plant will house four, 250MW single-stage reversible Francis pump-turbines (Water Power & Dam Construction, 2010).
2.4.2 System efficiency

Pumped-storage hydro plants do not create new energy; rather it is a net consumer of energy due to the energy losses incurred due to equipment efficiencies and hydraulic losses during the pumping and generating cycle. The pumped-storage hydro turnaround efficiency (also known as wire-to-wire efficiency) is the ratio between the energy supplied while generating and the energy consumed while pumping. This efficiency depends of both the pumping efficiency ($\eta_p$) and generation efficiency ($\eta_g$). Thus, the turnaround efficiency of any pumped-storage hydro project ($\eta_h$) is:

$$\eta_h = \eta_p \times \eta_g$$

Turnaround efficiency values usually range between 70 – 85% (Ter-Gazarian, 1994).

2.4.3 Equipment configuration and characteristics

Regarding equipment characteristics, pumped-storage hydro plants can use reversible turbines or turbines and pumps separately. Head limits of these units are similar to those of conventional hydropower projects and depend on the type of unit being used, which are: Variable speed units, single-stage reversible units and multi-stage pump turbines.

**Variable speed units** are usually used for heads between 200 – 400 m. Variable speed units can provide automatic frequency control, which is used for load regulation, in both generation and pump mode. These units are also designed for fast start from an off state and for fast load ramping to full-load condition (ASCE, 1996). Typical performance characteristics of these units are as follows:

- Shutdown to online: 60-90 seconds.
- Online to full-load generating: 5-15 seconds.
- Spinning-in-air to full-load generating: 5-15 seconds.

**Single-stage units** are usually used for heads up to 800 m. These units are able to provide automatic frequency control in generation mode only. The centrifugal Pump/Turbine arrangement is the most currently used technology. Single-stage units can be arranged as a three-set unit (turbine, pump and generator/motor) or a two-set unit (reversible turbine/pump and
generator/motor). Two-set units are usually 30% cheaper than three-sets units (ASCE, 1996). The drawback is that the pump starting regime is complicated and the changeover time is longer. Table 2.4 summarizes changeover time for these configurations.

Table 2.4: Pumped-Storage Hydro Changeover Time

(Source: Adapted from ASCE, 1996).

<table>
<thead>
<tr>
<th>Mode Change</th>
<th>Changeover times in seconds</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Three-set unit(s)</td>
</tr>
<tr>
<td>Standstill to full-load generation</td>
<td>120</td>
</tr>
<tr>
<td>Standstill to full-load pumping</td>
<td>180</td>
</tr>
<tr>
<td>Full-load generation to full-load pumping</td>
<td>120</td>
</tr>
<tr>
<td>Full-load pumping to full-load generation</td>
<td>120</td>
</tr>
</tbody>
</table>

Multi-stage units are usually applied for heads higher than 800 m and up to 1500 m. These units are not able to provide automatic frequency control. Multi-stages units have lower efficiencies and longer changeover time than single-stage units. An alternative arrangement combining multi-stage units with Pelton turbines allow for load regulation capability (ASCE, 1996).

2.4.4 Possible benefits of pumped-storage hydro

Nowadays, pumped-storage hydro has evolved into an electric system resource with many functions that contribute to the power system reliability. These functions are:

Peak-time energy: Pumped-storage hydro can provide the electric system with energy during peak hours, displacing other generation sources such as gas turbines or other hydro plants.

Load levelling: It can consume electricity during off-peak hours, reducing the difference between daily peak capacity and daily off-peak capacity.

Ancillary services: It can provide regulation and load following if outfitted with an automatic generation control (AGC) system. It can also provide both spinning and stand-by reserves, system frequency control, and can respond and correct for low frequency occurrences.

Improvement of the thermal system’s efficiency: Off-peak load of pumped-storage hydro generally results in less cycling of the thermal units and fewer stops and restarts of these units, thus improving their efficiency and reducing maintenance costs.
Voltage regulation: A pumped-storage hydro can operate in condenser mode to generate or absorb reactive power for system voltage regulation.

Transmission system benefits: Pumped-storage hydro may provide reserve capacity needed to permit more effective utilization of the transmission system.

Despite the large amount of functions that a pumped-storage hydro plant can provide, the development of these projects is heavily constrained by the availability of suitable sites and its significant capital costs. The choice of suitable sites is determined by topographical and geological characteristics, environmental considerations, and remoteness of the site from the electric grid (Ter-Gazarian, 1994). CAISO (2007) also indicates that large pumped-storage hydro facilities are quite costly, and there are very few locations where they can be built. Other major barrier for construction of new pumped-storage hydro facilities is not the technology but the absence of market mechanisms that recognize the entire value of the storage facilities and financially compensate them for the services and benefits they can provide.

2.4.5 State-of-the-art pumped-storage hydro development

The assessment of new pumped-storage hydro projects today must include several of the benefits previously mentioned in order to be economically feasible. According to personal communications with energy trading experts from Powerex, energy markets in North America have evolved towards reduced intraday variations of energy prices, so new pumped-storage hydro projects that are only benefit from off-peak and peak price differential are very difficult to justify.

One interesting benefit of pumped-storage hydro is the benefits of providing spinning reserve from pump loads, with benefits for both the electric system and pump load providers (Kirby et al., 2003). In this way, pumped-storage hydro projects can provide reserves in both generation and pumping mode. The same concept can be applied for regulation reserves if variable speed units and the proper electronic equipment and controls are installed.

The development of variable speed pump units was the breakthrough that improved the efficiency and the operating range of pumped storage power plants, especially in the case of
large variations in pumping. This has been made possible by the development of high power semiconductors and power electronic drives. Some units have been developed and put in operation during the last two decades (Suul et al., 2008). Most of the experience with such units is from Japan, where there has been a need for controllable energy storage to control frequency of the power system during night without using the most expensive thermal generation. Such is the case of the Takami Project in Hokkaido. This project has one 103 MW pumped-storage unit (Unit 2), which uses rotor alternating-current excitation and high technology power electronics to achieve variable speed operation in both generation and pumping modes. Thereby, it provides complete regulation of the load both in pumping and generation modes (ASCE, 1996). These types of units can access to a greater range of products when participating on ancillary service markets.

In Europe, recently the Goldisthal power plant in Germany, with two 300 MW variable speed units, was commissioned. Ohkawachi power station in Japan has the largest units of this type that have been built until now, with machines rated for 395 megavolt ampere (MVA), and with 72 MW cycloconverters for the rotor circuits (Suul et al., 2008).

In the area of site development, more sites suitable for pumped-storage hydro plants can be available if seawater pumped-storage is developed. Seawater pumped-storage may have several advantages over conventional pumped-storage hydro such as lower civil construction cost and greater site availability (Deane et al., 2010). However, only one seawater pumped-storage exists today in Okinawa, Japan. The plant started operation in 1999 with a capacity of 30 MW at a head of 136 m. Seawater pumped-storage technology has yet to develop a commercial track record to be more attractive for large scale development.
2.5 Review of Optimization Models for Electric System Operations

Several authors have proposed new models to solve the problem of optimizing the operation of electric systems that include wind power and/or pumped-storage hydro facilities. The approach of the methodology proposed depends on the characteristics of each particular problem.

The models proposed can be categorized in three groups:

a) Optimization models for wind power and pumped-storage hydro facilities aiming at maximizing the revenues of their combined operation.

b) Optimization models to assess the integration of wind power as an asset of a hydropower dominated utility in the electric system.

c) Optimization models to assess the integration of wind power in the context of an electric system with hydropower storage capability.

In this research project the benefits of pumped-storage hydro are evaluated within the context of a hydropower dominated utility and therefore the main focus was on group b) models. However a review was also done on some works for the categories a) and c), in order to study other optimization methods which can help to identify the benefits and optimum operation of pumped-storage hydro facilities with wind power.

2.5.1 Overview of optimization techniques

Before reviewing different optimization models, it is crucial to know the general characteristics of the most common optimization techniques proposed in the literature for solving problems related to the operation of Wind Power and Pumped-storage hydro.

Linear programming

Linear programming is the most powerful method of constrained optimization available (De Neufville, 1990). It can deal, usually very fast, with problems involving tens of thousands of variables and constraints, which are virtually intractable by other methods of analysis. This technique assumes that the problem to be solved can be described by linear, additive and continuous functions. Using these assumptions, the feasible solution of this kind of problems are convex and the optimum is located at an edge of the feasible region.
Integer programming

Integer programming is a variation of linear programming which forces the solution for some variables to be integer. The disadvantage of this technique is that it is expensive in terms of computer-processing time, usually three to ten times longer than the time required to solve linear problems. Most of the time it is combined with linear programming in what is called \textit{mixed integer programs} (only some variables of the problem are integer), which is the case for example of a linear problem with some binary variables.

Dynamic programming

Dynamic programming is a method of optimization which can be applied to problems that: are nonlinear, have non-convex feasible regions and have discontinuous variables. In the dynamic programming method, the decision in each time step is made based on the outcome of each decision in the next stage (or timestep). In this method the end of the study is set to be the first stage and is used to initiate the decision making process in a backward recursion. This method is also very costly in terms of computer time, but it can be combined with linear programming to exploit the advantages of both methods. Dynamic programming methods are commonly used for solving hydro reservoir management problems (Yakowitz, 1982).

Evolutionary algorithms

Evolutionary Algorithms are methods influenced by evolutionary biology, which uses different functions such as crossovers, mutation, and inheritance to arrive at optimal solution. Its parameters are in the form of strings and are called chromosomes. In each step “parental” chromosomes are combined randomly to generate a second set of parameters called “new generation”. Accordingly, the fittest parameters (the best results) are chosen using a function called the “Roulette Wheel”. After several iterations the generation produced is taken as the optimal solution. Several studies have been carried out on the potential use of genetic algorithms to solve energy resource optimization problems (Abdalla, 2007).
2.5.2 Treatment of uncertainty in optimization models

Regarding the treatment of uncertainty, optimization models can be usually categorized into two main groups:

- **Deterministic Models**: In a deterministic model, parameter and coefficients are known in advance and the model does not explicitly address uncertainty.

- **Stochastic Models**: Stochastic models take into consideration the presence of some randomness in one or more of the input parameters or variables.

Stochastic optimization allows taking a good solution *ex-ante* given statistical information of a random event. This solution is certainly not as good as if the solution would have been taken with perfect knowledge of the variables. However, at the same time, this solution is hardly ever a bad solution (Kall and Wallace, 2003).

In stochastic optimization, there are two sets of decisions (variables) to be taken. One set are those decisions that have to be taken without full information on some random events. These decisions are called *first-stage decisions*. Later, full information is received on the realization of some random vector. Then second-stage or *recourse* decisions are taken, which are influenced by both the first-stage decision and the random event. In stochastic optimization, both set of decisions are chosen in an optimal way (Birge et al., 1997).

When looking for a stochastic solution, basically two possibilities exist. A first possibility would consist of looking for a “safe” solution, which means take a set of first-stage decisions that are feasible for all possible realizations of the random variable. A solution like this is called a **fat solution** and reflects total risk aversion of the decision maker because it does not consider any action to be taken during the realization of the random variable to correct a decision. These solutions are usually rather financially expensive.

The second possibility assumes that the stochastic problem is solved using a **stochastic program with recourse**, which means that there are some actions or recourse decisions that can be taken during the realization of the random event to correct the events of the first-stage decisions. Then, the solution takes the expected value of the cost (or benefit) of the recourse decisions. Stochastic program with recourse are less financially expensive than fat solutions but it may become very
large in scale and computationally intractable. However, its particular block structure is amenable to specially designed algorithms such as the Bender Decomposition algorithm.

Stochastic parameters are of extreme importance in models of an electric system modeling wind power, due to the relatively high variability and uncertainty of the wind power generation. Other model parameters that can also be treated as stochastic in these types of problems are load demand, natural inflows, and market prices.

### 2.5.3 Selection of scenarios for stochastic optimization

To represent random variables, it is necessary to prepare **scenarios** (usually called stochastic scenarios) that are able to represent the possible outcomes of random events. The random variables are represented by continuous distributions functions or by discrete distributions functions, both of which can have a significantly large number of outcomes. A random variable represented by a large number of scenarios can be long and difficult to solve because the models explicitly or implicitly require numerical integration over such variable (Høyland and Wallace, 2001).

Therefore, the process of scenario generation and selection is very complex and it has been a topic of study for many researchers. The process of generating scenarios requires first a sample of the random variable (e.g. sample of inflow records, sample of wind speed records). Scenario sampling can be either random using Monte Carlo generation methods or can follow a defined distribution function.

Once a distribution function has been sampled, it can still have a large number of scenarios. Then a method for reducing the number of scenarios should be used. These scenario reduction methods involve the use of computational algorithms and heuristics to select the correct number of scenarios and appropriate probability that represents the distribution function of the random variable accurately. Different scenario reduction methods exist and they depend on the kind of random variable that needs to be represented. Some of these methods for power system management can be found in the work of Høyland et al. (2003), Gröwe-Kuska et al. (2003) and Dupacova et al. (2003).
A good example of scenario generation applied to the optimization of the operation of wind power and pumped-storage hydro facilities is presented in the work of Gonzalez et al. (2008). In this case there are two stochastic parameters: wind power output and market prices. The first-stage decisions are the hourly bids to be submitted to the day-ahead market and the recourse decisions are the operation plans of the pumped-storage hydro plant for each possible realization of the random variables (wind production and market prices). To deal with the two sources of uncertainty, they used a discrete representation of scenarios using a Markov chain in order to build a stochastic tree as the one shown on Figure 2.3. Note that both random parameters are merged into single scenarios.

![Figure 2.3: Uncertainty Representation of Wind and Market Prices](Source: Garcia Gonzalez et al. 2008).

### 2.5.4 Modeling of wind power and pumped-storage hydro

The work under this category is focused on optimization problems to maximize the revenues of the joint operation of wind farms and pumped-storage hydro. In the operation of these facilities, the literature indicates that revenues from energy market transactions provided the benefits for both wind farms and pumped-storage hydro. Therefore, the models proposed focused on
identifying the optimum daily operational strategy to be followed by the system operator to operate both wind farms and pumped-storage hydro, provided that a wind power forecast was available. This optimum strategy allowed facilities’ owners to bid certain amount of energy in the market. In all these works, the representation of the wind variability and uncertainty was a key factor to accurately model real operation scenarios.

Regarding the design of a pumped-storage hydro plant to be combined with the output of several wind farms, Anagnostopoulos et al. (2007) and Bueno et al. (2005) proposed models to size this plant on islanded electric systems. Anagnostopoulos et al. (2007) used an evolutionary algorithm to derive financial indicators, while Bueno’s analysis uses an iterative method of a life cycle cost assessment. Both models are deterministic and the wind temporal variation was managed using wind power time records. The benefit of this facility was estimated as a set of prices to be paid multiplied by the amount of energy supplied by both the pumped-storage hydro and the wind farms.

Castronuovo et al. (2004) proposed an optimization model for the hourly operation of a wind farm with a pumped-storage hydro plant for the Portuguese energy market. In this market, wind energy was paid a fixed tariff times an hourly factor to encourage wind power producers to deliver energy when it is most needed. In his work, the available wind power was assumed as a stochastic quantity, represented by two series of hourly values: the wind-power average value and the magnitude of its standard deviation. The model randomly generated samples of available wind-power series using a Monte Carlo simulation approach, each of them representing a wind-power scenario. Each scenario was then optimized using a deterministic optimization model. The results show that the utilization of the water storage potential produced an increment in the wind park economic profit, because wind energy is preferentially delivered to the network during peak (high price) hours.

Bathurst et al. (2002, 2003) explored the transactions of wind power in market systems that include ex-post imbalance energy markets to manage the difference between energy bids and real dispatch. In this way, the power producers who dispatched less than the amount of the energy bid were penalized while those producers that dispatch more than the amount of the energy bid are rewarded proportional to the ex-post price of the imbalance market. This market mechanism highlighted the importance to add the question of how much wind power should be sold in order
to avoid significant future penalties. In Bathurst et al. first work (2002) scenarios were created using Markov Chains to estimate the imbalance probability and cost for different levels of wind generation. With this information the wind power producer could choose among different operation policies and optimized its economic benefit. In Bathurst et al. second work (2003), the optimum dispatch of a generic electrical energy storage facility was calculated taking into account the short-term power exchange and the expected imbalance penalties of a wind farm. This information was also used to obtain the best storage size capacity. They demonstrated that it was possible to obtain significant added value of the storage facility, but the magnitude of imbalance prices was a significant factor of the storage facility’s added value.

Matevosyan et al. (2006) also proposed a model to minimize the imbalance cost that should be paid by the wind power producer after an energy bid was allocated in a day-ahead spot market. The bid strategy proposed considered selling in the spot market a certain amount of the wind energy forecasted that minimized possible imbalance cost. The wind energy bid was prepared using a wind forecast for the next 12 to 36 hrs plus a time series of different wind forecast error scenarios. The wind forecast error scenarios are constructed using an Autoregressive Moving Average (ARMA) series. The scenario tree of wind power forecast errors were prepared using a scenario reduction method based on the Kantorovich metric (Dupacova et al., 2003). A case study was presented for wind energy biddings submitted to the Nordic energy market (Nordpool). In this study, six days of 2003 were tested and 50 wind forecast error scenarios were considered. The results of the simulations showed that the bidding strategy which minimized imbalance cost generally resulted in higher profits than the strategy where a player bids the forecasted wind power production and then pays imbalance costs.

Márquez Angarita et al. (2007) also proposed an interesting approach to minimize the imbalance between the wind energy that was bid in advance in the energy market and the output of the wind farms in real time. The paper presented a combined strategy between a wind generator and a hydropower generator to minimize wind energy imbalances and maximize hydro revenues using the Spanish energy market as a reference. The stochastic nature of the wind was represented using the probability density function of the wind energy forecast for the planning period. Again, as was proposed by Bathurst et al. (2002), to bid wind energy in short term markets it is necessary to know both the current actual wind energy production and the probability density
function of the forecasted wind for that level of production. Regarding the combined operation of the wind generator and the hydropower generator, the benefits of their combined operation were a function of the energy imbalance penalties. When the penalty was low, it was better to allow imbalances than to modify the water scheduling. High penalties, on the other hand, encouraged the hydro-generator to cover the wind deviations. This covering also depended on the water future value.

Fabbri et al. (2005) assessed the cost associated with the wind forecast error in the Spanish Electricity Market. A probabilistic methodology was proposed to estimate the wind forecast errors costs in the market for wind generators. Generators must buy or sell energy production deviations due to prediction errors when they bid in day-ahead or hour-ahead energy markets. The prediction error was modeled by a probability density function that represented the accuracy of the prediction model. Then, production hourly energy deviations and their associated trading costs were calculated. The results of three case studies showed that the error prediction costs can reach as much as 10% of the total generator energy incomes from wind power sales.

Another interesting approach was presented by García-González et al. (2008). He investigated the combined optimization of a wind farm and a pumped-storage hydro plant from the point of view of a generation company in the Spanish market environment. The optimization model was formulated as a two-stage stochastic programming problem with two random parameters: market prices (modeled using Markov chains) and wind generation (modeled using a statistical-numerical approach). The optimal bids for the day-ahead spot market were the “here and now” decisions while the optimal operation of the facilities are the recourse variables. A joint configuration was modeled and compared with an uncoordinated operation in the case study. The paper showed that, the coordination of both generators resulted in an increment of the profit for both the wind farm and the pumped-storage hydro plant, as the joint operation model achieved higher profits than the addition of the individual profits obtained in the uncoordinated model. The expected profit increase was 2.53% and the imbalance penalty in the joint-operation model was reduced by about 36%.
2.5.5 Modeling of wind power integration in hydropower utilities

As mentioned in Section 2.2, when hydro-dominated utilities integrates wind power into their system, the cost of the wind integration impacts is not simply related with the production-cost of the hydropower utility. Opportunity costs defined by market prices and the trade-off between present benefits obtained from energy market transactions, and the potential expected long-term value of the water resources should be considered in the assessment.

Vogstad (2000) investigated the system benefits of incorporating wind power in the hydropower production scheduling using a stochastic dynamic programming model for the hydro-dominated Nordic power system (Nordpool). This model was used to schedule hydropower production and to forecast market prices. The added value of wind power was calculated as the difference of the system production costs between a simulation case with wind power and a reference case without wind power. The model considered implicit the option of storing wind power on the hydropower reservoirs. The system production costs were adjusted for the changed in the value of the storage water in the reservoirs at the end of the year. The results of 10 simulations showed that if wind energy production was incorporated in the hydropower production scheduling model, the value of wind power was incremented up to a 9% compared with the value of wind energy sold at a weekly spot price.

Matevosyan et al. (2007) proposed a day-ahead planning algorithm for a multi-reservoir hydropower system coordinated with wind power to avoid wind energy curtailments in areas with limited transmission capacity. The hydropower planning algorithm was formulated as a stochastic optimization program with many wind power production scenarios considered simultaneously. The hydropower system was planned for a week with the initial reservoir content assumed known and the reservoir content at the end of the planning period fixed in accordance with the midterm production planning. In this work, wind power and hydropower were assumed to be owned by different utilities, but they share the same transmission line(s), and the hydropower utility had priority for the transmission capacity. Therefore, if transmission congestion occurs, the wind farm was disconnected or its energy was curtailed. With a coordination mechanism, the hydropower utility reduced its generation during transmission congestion situations, avoiding wind power curtailments. The wind power utility was assumed to be paying the hydropower utility for the coordination service. Similar to García-González’s work...
(2008), this planning algorithm provided the hydropower utility with optimal hourly bids to the
day-ahead market (spot market), considering uncertainty of the wind power forecast. In this case,
the wind power forecasted is simulated using autoregressive moving average series (ARMA) for
the wind speed forecast error. The wind scenario tree was prepared using a scenario reduction
method based in the Kantorovich metric. In this paper, only the spot market was considered.
Consequently, the production plan once submitted to the spot market could not be changed
during the day. This means that the stochastic optimization problem used a fat solution to satisfy
all constraints at any outcome of wind power production scenarios. In the case study analyzed
by the author, wind power curtailment was reduced in almost 50% and it resulted in additional
income to the hydropower utility.

Evans and Shawwash (2009) studied the value of wind curtailment for the BC Hydro system
under different wind penetration scenarios (3% to 12%). The model used in this research
performed a hydrologic simulation in parallel to an optimization of the hydroelectric generator’s
assets and considering the integration of wind generation using a linear programming technique.
The model optimized the hydroelectric generation operations on the two largest river systems in
British Columbia (Peace River and Columbia River). It also optimized power sales across the
transmission ties to the United States and Alberta. Long-term water storage targets were taken
from a long-term BC Hydro operations simulation model (HYSIM). The model also considered
transactions of unused capacity to value the system flexibility and blocked reserves to cover
within the hour load and wind variability and uncertainty. The results showed that BC Hydro
could increase the value of wind energy very slightly (0.1% to 0.02%) during a dry water year if
allowed the option of curtailing wind power, but still requiring it to pay the wind power producer
for all available wind power. Under the same requirements, but during a wet water year, the
value of wind energy could increase a greater amount (0.2% to 1.0%) for wind capacity
penetration levels 3% to 12%. For either the dry or wet water year, total annual wind energy
curtailment was less than 2.5%.
2.5.6 Modeling of wind power integration in electric systems with storage

In the following literature review, the benefits of storing energy are evaluated within the context of the whole electric system and the integration of large amounts of wind power.

The alternative of using hydro storage to cope with the wind variability and uncertainty has been proposed by many authors. Matevosyan et al. (2007) provided a discussion of four alternatives for large-scale wind power integration in power systems with transmission bottlenecks: revision of the methods for calculation of available transmission capacity, transmission network reinforcement, excess wind energy curtailments and excess wind energy storage in hydro reservoirs. Regarding wind energy storage in hydro reservoirs, storing wind energy in existing conventional hydropower plants situated in the same area may be more convenient than using pumped-storage hydro, which can be very expensive.

Benitez et al. (2008) assessed the overall economic impact of introducing wind power into the electrical grid. She also evaluated the trade-offs of increasing levels of wind penetration, as well as the costs of reducing CO₂ emissions. They proposed a deterministic nonlinear optimization program of an electrical grid that accounted for fossil-fuel power plants, wind power, hydropower and pumped-storage hydro, and searched for the best possible allocation of energy among generators. The objective function proposed seeks to minimize the total generation cost (i.e. the sum of operation cost, maintenance cost and start-up cost) of the electric system. An application of this model analyzed the impact of wind power penetration in the Alberta electric system. The analysis showed that an increment in wind power penetration creates imbalance in the system and must therefore be countered with an increase in backup capacity via a new peak-load generating capacity. The costs of this additional peak-load capacity might represent some 15% to 30% of the investment costs of a wind farm, and are often ignored in the calculation of the benefits of wind power. The costs of wind penetration were lower if hydro storage was available. They also found that for systems with less storage capacity for power generation, it become necessary to increase the size of existing reservoirs and/or add a pumped-storage hydro plant.

A stochastic version of a model similar to Benitez’s work is proposed by Swider et al. (2006). The model was based on a stochastic optimization of the electric system operation costs. These features allowed the system to adapt on increasing wind integration and energy policies (i.e.
increasing CO₂ prices). Stochastic scenario trees were built based in the intermittency of wind generation data series. The approach proposed to construct the scenario trees follows the structure of a Markov Chain. This means that a typical day “t” (from N stages) is subdivided in S stochastic states. Transition probabilities are given for each state s and each stage t. In this paper the stochastic states were defined as low, medium and high wind generation, while the stages were represented by the days of the analysis. A case study applied this model to estimate the change in the system operation costs due to large-scale wind integration in Germany. The results indicated that stochastic modeling of wind generation did not alter the estimated system operation cost in the considered cases. This was due to the relatively minor impact of additional wind generation on the marginal power plant cost in the system. However, the marginal value of wind applying this stochastic model version was generally lower than the value estimated applying a deterministic model. The results also showed that the increased fraction of wind serving demand had little influence on the marginal electricity price.

Several models have been proposed to assess wind integration impacts at the balancing authority level. Most of these models were system-specific but, similar features were encountered in all these models. This was the case of the optimization models used in the Minnesota (Enernex, 2006) and New York (GE, 2004) wind integration studies.

Perhaps the most complete electric system model available to assess wind power integration impacts is the one developed by the WILMAR project that was supported by the European Community. The model was presented in a series of papers by Brand et al. (2004, 2005). The WILMAR model described an ideal and efficient market operation by using a stochastic linear programming model to simulate power market transactions on an hourly basis with rolling planning. The model included four types of markets: i) a day-ahead market for physical delivery of electricity, ii) an intraday-market, iii) a day-ahead market for automatically activated reserve power and iv) a market for district heating and process heat. The model derived electricity market prices from marginal system operation costs. The model optimized the unit commitment and dispatch taking into account the trading activities of the different actors on the different energy markets. Additionally, different restrictions such as transmission constraints or capacity constraints of the power and heat generating units were taken into account.
The different scenarios of the model were based on different wind power generation scenarios. The wind power generation was based on data about wind speed and historical forecast errors for the wind speed. A Wind Speed Forecast Error module assumed a multidimensional ARMA time series to estimate the wind forecast error. The ARMA time series contain the usual error terms. These were simulated by Monte Carlo simulations resulting in a large number of scenarios for the wind forecast error scenario tree. In order to reduce the number of scenarios, a stepwise backward scenario reduction algorithm was used and it was based on the approach developed by Dupacova et al. (2003), which minimize the Kantorovich distance between two scenarios.

In a second paper (Brand et al., 2005), the WILMAR model was applied to the German market to analyze five typical weeks of the year, where three regions and 40 different types of units were defined. The results indicated that transmission bottlenecks were caused by varying wind power production in Germany. The model also showed that annual system operations costs are reduced by €1.43 billion when wind power is integrated in the German electric system. This savings on system operating costs are in a range of 10 – 18 € per MWh of wind power produced depending of the season. Overall, the savings per MWh were rather low, compared to current prices at the German wholesale market. This reflected the cost for reserve power and reduced efficiency at part load operation induced by wind power. Moreover, prices tended to be lower when the wind was blowing, thus reducing further the market value of the wind energy produced.
3 MODELING METHODOLOGY

This chapter provides information about the model that was developed and used in this research, including a brief description of the BC Hydro model which was used as a starting point and the modifications made to this model to allow the assessment of wind power integration impacts and the benefits of pumped-storage hydro plants. The methodology that was used for the feasibility analysis of the proposed pumped-storage hydro plants was also included in this chapter.

3.1 The BC Hydro System Optimization Model

BC Hydro uses several optimization and simulation models for operational planning. Each model has been formulated depending on the planning level and study purposes: long term, medium term, short term. Results from these simulation and optimization models are used to determine operation schedules, reservoir rules, energy dispatch guidelines, etc.

The model used in this research is mainly based on the BC Hydro Short Term Optimization Model (STOM) developed by Shawwash (2000). STOM is a deterministic linear programming model that determines the optimal hourly generation and trading schedules in a competitive power market, maximizing the value of the BC Hydro resources from market transactions in the Western U.S. and Alberta energy markets. This model is used by the BC Hydro system operation engineers for post-mortem studies to evaluate the performance of the day to day system’s operation and in many cases to help them developing short-term system generation plans.

STOM was conceived and used only for short-term operations (1 – 168 hrs). Later the model evolved into a new version capable of performing medium-term operational planning studies extending from one week up to many years. This new model is known at BC Hydro as the Generalized Optimization Model (GOM). GOM has been used to assess water use planning operating regimes for the Peace and Columbia River systems and to estimate the trading benefits arising from transmission system and capacity expansion, and generating units efficiency upgrades. The model was also used and extended the Wind Integration Team at BC Hydro as reported by Evans (2009) in his research to study the value of wind curtailment in the BC Hydro system.
The GOM model used by Evans (2009) to the BC Hydro generation system was further developed in this study to include new features required in the assessment of wind power and pumped-storage hydro integration. A description of the proposed model is provided in the next sections. The material in these sections was adapted from Shawwash (2000) and Evans (2009).

3.2 Characteristics of the BC Hydro Generalized Optimization Model
The GOM model combines a hydraulic simulation with the optimal dispatch scheduling of selected generation resources of the BC Hydro system to maximize the value of hydropower generation assets. The model was written in AMPL, a mathematical programming language, and the linear programming solving technique is applied using the CPLEX solver. The main features of this model were described by Shawwash (2000). A summary of the GOM model characteristics is provided in the following paragraphs:

1. **Representation of BC Hydro Hydroelectric System**: A typical hydroelectric generation system consists of sets of rivers, tributaries, reservoirs, powerhouses and additional hydraulic facilities such as intake structures, spillway gates and weirs. Facilities that are serially connected are hydraulically connected as well because the outflow from the upstream plant is a part of the total inflow to the downstream plant’s reservoir. A matrix structure was used to capture the complex nature of inflows to and from the reservoirs in the BC Hydro system. This matrix describes flow sources and destinations in a set of connected generating facilities. Several incidence matrices were used to describe the turbine discharges, spill discharges and inflows from one reservoir to another.

2. **Hydraulic Modeling of Reservoir Operations**: The model determines the amount of water that is discharged from a plant and used for power generation (turbine flow) or spilled. It also determines the amount of water stored in the reservoir for future use through a temporally connected mass-balance equation. The operation of a hydro facility is governed by certain rules that were set as constraints for technical, environmental, regulatory, navigational, and long-term planning requirements.

3. **Modeling of Hydropower Generation**: Power generation is a function of both gross head and turbine discharge, which are both products of the hydraulic modeling of the reservoir. This is complex to represent in a linear program. To deal with this issue, the model derived...
optimal power generation using data from a separate static plant unit commitment program that employs a dynamic programming algorithm that tabulates the optimal plant discharge for each increment in plant loading, forebay, and for each unit availability combination. The resultant family of piecewise linear curves are used to describe the plant generation at each time-step as a function of forebay level, turbine discharge and unit availability.

4. **Load Resource Balance:** The generating facilities are usually operated to meet the system firm demand and market transactions. In addition, generating facilities set aside reserve generation capacity to meet real-time operational fluctuations, contingencies and to provide ancillary services. An additional set of equations was included in the model to meet these requirements.

5. **Import and Export Transfer Capability:** Tie line maximum and minimum available transfer capability for market sales limits were also included in the model.

6. **Objective Function:** For a hydroelectric system with significant multi-year storage, the prime objective is to first meet the domestic load demand and then to make the optimal trade-off between present benefits, expressed as revenues from energy transactions, and the potential expected long-term value of resources, expressed as the marginal value of water stored in reservoirs. The objective function in GOM was then represented by the following equation,

Maximize:

\[
\sum_{t=1}^{T} (P_{\text{export}} \times R_{\text{export}} t - P_{\text{import}} \times R_{\text{import}} t) + \sum_{j=1}^{J} (V_{jT} - V_{\text{Target}}) \times MVW_{j} = (3.1)
\]

The first term represents the sum of revenues (or costs) accrued from hourly energy exports \(P_{\text{export}}\) minus the cost of imports \(P_{\text{import}}\) given hourly market prices in dollars per megawatt-hour ($/MWh) for exports \(R_{\text{export}}\) and imports \(R_{\text{import}}\) respectively. The second term represents the sum of storage cost (or added storage value) of deviating from the terminal target storage level at target hour \(V_{\text{Target}}\). For each optimized reservoir “\(j\)”, multiplying the difference between the optimized storage at the target hour and the target storage by the marginal value of water \(MVW_{j}\), in $/m, yields its storage cost (or added storage value). The marginal value of water and the target storage for each reservoir were predetermined from long term planning studies, which yield a water value function. Stochastic dynamic-programming and other
stochastic optimization models are typically used to establish the value of water stored in reservoirs as a function of storage levels, as illustrated in Figure 3.1 (Abdalla, 2007); (Druce, 1990).

![Figure 3.1: Value of Water in Storage and Marginal Value of Water for Timestep](Source: Shawwash, 2000).

### 3.3 Wind Integration Assessment Module

The optimization model described in the section above was designed to optimize the operation of a hydro-dominated electric system with limited number of gas-thermal stations. New features were added to GOM by the Wind Integration Team at BC Hydro as described by Evans (2009) to expand the model to assess the value or curtailing wind power. A summary of these features that were used in this research are provided below:

1. **Wind energy as a generation resource:** In order to assess the value of the additional wind energy in the optimization problem, wind energy was added to the load-generation resource balance. A separately simulated time series of wind energy production was included as a “must take” resource (or a fixed parameter) in this research.

2. **Contingency reserves:** The original GOM model required BC Hydro hydropower plants to block 5% of their capacity to cover any contingency event, such as unplanned generation or transmission outages. The new version of GOM required that hydropower
plants must also provide contingency reserves for wind generation, which corresponded to the 5% of the wind hourly generation.

3. **Operating reserves:** The original GOM model held an additional 6% to about 14% of its generation capacity to manage intra-hour fluctuations in electrical load, varying month-to-month. These percentages were based on the planning criteria used by BC Hydro. In order to assess the amount of reserve capacity (regulation reserves to cover minutes-to-minutes fluctuations and following reserves to cover from ten minutes to an hour fluctuations) that wind energy could require to manage its intra-hour fluctuations, a new methodology was developed and used to manage load and wind variability. A certain fraction of the hydroelectric AGC unit capacity was blocked to manage load and wind within-the-hour variability and uncertainty (as regulation and following reserves). The generating capacity allocated as reserves could be provided by any of the optimized hydroelectric plants. However, regulation reserves can only be provided by hydroelectric units equipped with AGC equipment because this equipment is capable of managing the minute-to-minute fluctuations in load and wind.

4. **Slack generating capacity valuation:** Nowadays, electric utilities require and trade in markets two main products: electrical generating capacity (which can provide ancillary services) and electrical energy. For hydropower generation units, these are represented by the generating capacity of the hydro turbine/generator unit, measured in MW, and the electrical energy measured in MWh. If a market exist, it is important that the generating capacity of any electric utility is properly valued. GOM was modified to include the valuation of unused available generating capacity (slack capacity) that could be exported via transmission interconnections to adjacent regions. This generating capacity was included in the objective function and assigned a market value. Consequently, the capacity required to provide load and wind reserves within each hourly time step was incorporated in the objective function as a cost when the capacity is used by either load or wind. The slack generating capacity was included as a variable and it was also optimized. The new objective function can then be represented by the following equation:
Maximize:

\[
\sum_t^T (P_{\text{export}} t \times R_{\text{export}} t - P_{\text{import}} t \times R_{\text{import}} t) + \sum_j^J (V_{jt} - V_{\text{Target},jt}) \times MVW_j + \\
\sum_j^J \sum_t^T \left( \text{Cavail AGC}_{\text{export}} j t \times R_{\text{AGC}} t \right) + \sum_j^J \sum_t^T \left( \text{Cavail noAGC}_{\text{export}} j t \times R_{\text{no AGC}} t \right) - \\
\sum_j^J \sum_t^T \left( \text{reserves AGC}_j t \times R_{\text{AGC}} t \right) - \sum_j^J \sum_t^T \left( \text{reserves noAGC}_j t \times R_{\text{no AGC}} t \right)
\]  

(3.2)

Again, the first term represents the sum of revenues accrued from transactions in the energy market and the second term represents the sum of water storage cost (or value) as reviewed in Section 3.2. The third term represents the sum of revenues accrued from transactions of slack capacity from AGC hydroelectric plants (Cavail AGC_{\text{export}} j t) in the capacity market that can be exported in the capacity market at a price R_{\text{AGC}} t. The fourth term represents the sum of revenues accrued from transactions of slack capacity from non-AGC hydroelectric plants (Cavail noAGC_{\text{export}} j t) in the capacity market at a price R_{\text{no AGC}} t. The fifth term represents the cost of blocking capacity to provide reserves for domestic load and wind from AGC hydroelectric plants (reserves AGC j t) at a market cost R_{\text{AGC}} t. Finally, the sixth term is similar to the fifth term, but corresponds to non-AGC plants.

It can be seen that the model differentiate AGC and non-AGC hydroelectric plants, because the capacity provided by AGC plants can be used for regulation, which has a higher and different value from the capacity provided by non-AGC plants, which is commonly used for following reserves.

### 3.4 New Additions to the GOM Model

The GOM model was modified and divided into two parts (long-term and short-term) to assess the three main components of this research: benefits of the pumped-storage hydro system, incremental wind reserves cost and scheduling cost of wind integration. The long-term model, such as the one used by Evans (2009), was used to assess the benefits of pumped-storage hydro and the incremental wind reserve costs. This model also established reservoir storage trajectories for short-term simulations. A short-term version of the GOM model was formulated to simulate BC Hydro short-term planning process and to estimate the scheduling cost of wind integration.
3.4.1 Overview of BC Hydro short-term planning process and market transactions

Before describing the models proposed in this research, an overview of the BC Hydro short-term planning process, including how electricity is traded, is provided.

Short-term plans of BC Hydro generation units are prepared by operation engineers of BC Hydro’s “Shift Office”. This office is responsible for directing the short-term operation of the system. The office also works very closely with Powerex energy traders who buy and sell energy in the spot and forward markets in the U.S. and Alberta. The Shift Office is also in charge of directing real-time generation system operations. During real-time operations, engineers prepare pre-dispatch and unit-commitment schedules, and plant base points for the System Control Center, which physically operates the power system and is responsible for its reliability. The shift office also coordinates real-time and day-ahead market transactions with energy traders.

This planning process determines the preferred stack order for running the generation system and the potential energy budget for market transactions for the next seven days. Forecast system conditions for load, generating units and transmission line outages, weather, inflows, energy markets as well as real-time information is relayed to the operation engineers to aid the decision-making process.

From the above discussion, it is clear that energy markets significantly influence the short-term planning process of the BC Hydro system. Trading of BC Hydro resources is carried out by Powerex, a wholly owned subsidiary of BC Hydro and is governed by an agreement between BC Hydro and Powerex. Powerex buys and supplies wholesale power, natural gas for BC Hydro and ancillary services across North America. Powerex trades energy through forward (long-term) contracts with utilities and participates in electric power markets. Most of Powerex trades are done in these markets. The most relevant markets for BC Hydro are located in the U.S. Northwest (Mid-C, California) and in Alberta. Most of the energy markets transactions carried out by Powerex on behalf of BC Hydro are made in a day-ahead market.

During BC Hydro real-time operations, market opportunities are identified by Powerex traders who rely on the BC Hydro system flexibility. BC Hydro operation engineers coordinate system operation to allow Powerex traders to exploit these opportunities and they also arrange additional
power transactions in the hour-ahead markets or through bilateral trade bids in a **real-time market**. Trades in real-time markets are concluded at 20 minutes before the top of the hour. Usually real time trades are prepared one or two hours in advance of the delivery hour of the trade energy schedules.

Among the electric markets previously mentioned, the Mid-C market is the most important market for BC Hydro. This market does not have a formal day-ahead and real-time market pool similar to Alberta or California pools and the power transactions are made bilaterally between electric utilities in the Northwest. At the end, the process of buying or selling energy in this market requires two steps: one, a buyer or a seller has to be found and two, transmission have to be secured in advance of the deal. Transactions in real-time in this market are very limited mainly due to transmission lines constraints. California and Alberta on the other hand do have deregulated energy markets. In these markets power producers offer “bids” to supply power generation and the majority of the bid volume is close in a day-ahead market. These bids are then ranked by the Independent System Operator (ISO). The ISO is the entity that coordinates, controls and monitors the operation of the electrical power system to meet electricity demand at the lowest cost. The settlement price, or marginal cost, is then paid to all power producers. Deviation from day-ahead scheduled generation is usually penalized. This deviation can be settled in the **hour-ahead** and **real-time** markets to handle energy imbalances. Minute to minute load is managed by ancillary services, which can also be traded in the **ancillary services** market. Participation in the California and the Alberta markets can be difficult sometimes, particularly for real-time transactions, mainly due to transmission lines constraints and bottlenecks.

Generating capacity is also traded by BC Hydro, but mostly through long term contracts (e.g. Dynamic Schedules). Nevertheless, the California ISO, the Alberta ISO and the Minnesota ISO have ancillar services markets where generating capacity can be sold into or locally purchased (BC Hydro can only sell capacity to this market and cannot obtain any capacity for local needs). These markets can be a day-ahead market or an hour-ahead market. Participation of BC Hydro in ancillary service markets other than Dynamic Schedules is still very limited.
3.4.2 Scheduling cost of wind integration for BC Hydro

From the description provided above, it is possible to elaborate some conclusions regarding the electric power markets in which BC Hydro participates in. First, most of the transactions are made in day-ahead markets, when it is much easier to secure and purchase transmission tie capacity for the delivery of electricity. Second, real-time markets are very limited mainly due to the difficulty of securing transmission for electricity delivery in a short-period of time.

It is the author’s opinion that the evaluation of the scheduling cost of wind integration shall follow the following concept: “When wind power is scheduled to be sold in a day-ahead market, BC Hydro must have sufficient transmission and generation capacity in its system to cover for an extreme wind swings for day-ahead schedules”. The wind swing is defined as the difference between the forecasted wind generation and the actual wind generation delivered in real time. In other words, BC Hydro should be able to manage the wind forecast error (WFE) of the wind generation whether using its own generation resources, or trading all or a part of this energy imbalance in a real-time market. This results in reduced transactions in day-ahead markets than in a case without wind as more system flexibility is needed to manage wind variability. Water storage trajectories can also be affected due to the need to compensate for the WFE. In addition, some real-time market transaction opportunities can also be lost due to the negative market impacts. The assessments of all of the above impacts are expected to approximate the scheduling cost of wind integration for BC Hydro.

Nowadays, participation of BC Hydro in ancillary markets is very limited; nevertheless its potential future value is incorporated to approximate any costs attributed to wind integration as proposed by Evans (2009). Holtinnen (2008) also recommended netting out the effect of load uncertainty from the wind forecast error, and when the WFE is modeled in this study, then the load forecast error was included in this analysis.
3.4.3 Deterministic long-term model

The GOM model version used by Evans (2009) was extended to develop a one year operation plan for the BC Hydro system with wind integrated as a resource. The model optimized the operation of the main BC Hydro hydropower plants on the Columbia River and Peace River and market transactions, while the rest of the BC Hydro generation was modelled as a fixed variable input in the load resource balance. This operation plan produced the optimum reservoir forebay trajectory for each optimized hydropower plan. It also provided the energy trade schedules for the time steps modelled as well as when wind generation was stored in the reservoirs or exported along with other relevant information for energy planners.

To assess the impacts of wind integration, the following cases were prepared:

**Wind Case with Load Reserves (Case 1):** In this run the GOM model was used with the features mentioned in Section 3.3. Regulation and following reserves were included to cover within-the-hour load variability and uncertainty. Hydropower plants are needed to provide wind contingency reserves.

**Wind Case with Load and Wind Reserves (Case 2):** In this run, the same wind generation as in the previous run was used. Incremental regulation and following reserves to provide within-the-hour load and wind variability and uncertainty were also considered.

The outcome of these two optimization runs will produce different values of the objective function described in Section 3.3 (equation 3.2). The difference in the objective function between Case 2 and Case 1 indicates the additional cost that wind reserves incur on BC Hydro. In other words this difference provides the reserve cost of wind integration.

The reservoirs’ forebay trajectories for each of these runs were recorded to be used as targets in the short-term model. The starting and the ending reservoir forebay levels as well as inflow information used in the long-term model were obtained from a BC Hydro long-term system planning model which simulates this system for 30 years, HYSYM. The wind generation used in this analysis corresponded to an hourly time series of actual (simulated) wind generation. Details of the input data used for the long-term model are described in the Chapter four.
3.4.4 Stochastic short-term model

The objective of this model was to provide a simulation of the BC Hydro short-term planning process in order to assess the scheduling impact of wind integration. As was mentioned in Section 3.4.1, short-term BC Hydro generation schedules are typically prepared for a period of one week. This process is repeated every day to incorporate updated information of relevant information such as load, weather, market conditions, outages, in the planning process.

A detailed simulation of the scheduling process should produce the schedule of the whole generation system, with real and forecast data, and taking into account the uncertainty of some of the parameters used in the process such as weather, inflows, market prices, load and unplanned outages. Nevertheless, this process was simplified in this research for two main facts: The simulated system corresponds to a possible future configuration of the BC Hydro system; and the purpose of the simulation was to assess the impact of wind integration and not to study a detailed schedule of the system.

Then, the main features of the short-term model were:

- The model used for this simulation was a modified version of the GOM model and was adapted for a four-day-long simulation runs. Only four days were used to correspond to the longest wind forecast available from the Wind data study.
- The model optimized the main hydropower plants in the Columbia and Peace Rivers and modeled transactions in both day-ahead and real-time electric power markets.
- The model used a stochastic version of GOM because it takes into account different realizations of possible load and wind scenarios.
- Variables affected by the stochastic parameters were: plant power production, the allocation of reserves, the amount of slack capacity trade schedules and real-time market transaction schedules.
- Deterministic variables considered were day-ahead market transactions.

The model used corresponds to a stochastic optimization model with recourse. The first-stage decisions in this case were the export and import schedules for the day-ahead market. This decision was applied for all possible scenario realizations of load and wind. The recourse decisions were real-time exports, power generation, slack capacity valuation and reserves.
allocation. Although the slack capacity valuation and reserves allocation have to be in reality fixed in advance (i.e. they should be first-stage decisions), they were considered as recourse variables to relax the model solution process. Test runs made with these variables as first-stage decisions significantly increased the solution times needed and resulted in some infeasibilities.

The objective function used in the short-term model is formulated in equation (3.3):

\[
\text{Maximize: } \sum_{t=1}^{T} (P_{\text{exp DA } t} \times R_{\text{exp DA } t} - P_{\text{imp DA } t} \times R_{\text{imp DA } t}) \\
+ \sum_{s=1}^{N} \sum_{t=1}^{T} \rho_s \times P_{\text{exp RT } t,s} \times R_{\text{exp RT } t,s} \\
+ \sum_{s=1}^{N} \sum_{t=1}^{T} \sum_{j=1}^{\text{AGC}} \rho_s \times (C_{\text{AVAIL AGC } s,t,j} \times R_{\text{AGC } t}) \\
+ \sum_{s=1}^{N} \sum_{t=1}^{T} \sum_{j=1}^{\text{nAGC}} \rho_s \times (C_{\text{AVAIL noAGC } s,t,j} \times R_{\text{noAGC } t}) \\
- \sum_{s=1}^{N} \sum_{t=1}^{T} \sum_{j=1}^{\text{AGC}} \rho_s \times (R_{\text{RESERVES AGC } s,t,j} \times R_{\text{AGC } t}) \\
- \sum_{s=1}^{N} \sum_{t=1}^{T} \sum_{j=1}^{\text{nAGC}} \rho_s \times (R_{\text{RESERVES noAGC } s,t,j} \times R_{\text{noAGC } t})
\]

(3.3)

The first term represents the sum of revenues (or costs) accrued from hourly energy exports in the day-ahead market \((P_{\text{exp DA } t})\) minus the cost of imports \((P_{\text{imp DA } t})\) given hourly day-ahead market prices in dollars per megawatt-hour ($/MWh) for exports \((R_{\text{exp DA } t})\) and imports \((R_{\text{imp DA } t})\) respectively. The second term represents the expected value of the revenues from transactions in the real-time energy market \((P_{\text{exp RT } t})\) at a real-time market price \((R_{\text{exp RT } t,s})\) for different scenarios, \(s\), with probability \(\rho_s\). The third term represents the expected value of revenues accrued from transactions of slack capacity from AGC hydroelectric plants in the capacity market that can be exported. The fourth term represents the expected value of revenues
from transactions of slack capacity from non-AGC hydroelectric plants in the capacity market. The fifth term represents the expected cost of blocking capacity to provide reserves for load and wind from AGC hydroelectric plants. Finally, the sixth term is similar to the fifth term, but relative to non-AGC plants.

Note that the value of water stored in the reservoir was not included in the objective function because the reservoir volume at the end of the planning period was fixed in accordance with reservoir trajectories obtained from long-term planning process described in Section 3.4.3. Similar assumptions were made by Matevosyan and Söder (2007) in a planning model for a hydro power system coordinated with wind.

The short-term modeling was performed following a daily rolling planning algorithm. Figure 3.2 illustrates this algorithm. First, initial data is loaded in the model, including initial and target reservoir forebays, inflows, outage schedules, wind and load data and scenarios. Then, export and import schedules for day one are fixed using the results of the short-term plan prepared the previous day. The load and wind scenarios are also included in the model. Then, the optimization is run to obtain a unique export and import schedule for the next days given all possible load and wind scenarios. Finally the schedule obtained for day two is recorded to be used in the next day planning process as well as expected recourse information for day one, such as reserve cost, plant generation, the value of slack capacity and revenues from real-time exports. The cycle is repeated again for all subsequent days of the study.

This short-term planning process was shortened to represent only four days instead of the typical weekly planning used in BC Hydro to reduce simulation run time needed to compute the studies. The information used during day one represented perfect information, i.e. actual wind data for all wind scenarios and no load forecast error for all load scenarios. In reality this information is not available when schedules are actually prepared. Nevertheless, the uncertainty in this time horizon is much lower than the uncertainty in the next days and can be neglected for this modeling case.
To assess some of the scheduling impact of wind integration, two additional cases were added to the ones used in the long-term model:

1. **Actual Wind Case with Reserves + Load Scenarios (Case 3):** In this run, different load scenarios are added to the model. Wind generation is represented using an actual wind dataset. Incremental regulation and following reserves to cover within-the-hour load and wind variability and uncertainty were also added.

2. **Case with Reserves + Load and Wind Scenarios (Case 4):** In this run, different load scenarios and wind scenarios are added to the model. Incremental regulation and following reserves to cover within-the-hour load and wind variability and uncertainty were also added.
The difference in the objective function between Case 2 and Case 3 represented the cost of load uncertainty only. The scheduling cost of wind integration can be approximated as the difference in the objective function between Case 3 and Case 4.

### 3.4.5 Selection of scenarios for load and wind

As was indicated in the previous section, stochastic scenarios were used to represent load and wind intrinsic uncertainty. In total, four scenarios to represent load variation and twelve scenarios to represent wind variation were generated. The total combined scenarios used to represent load and wind uncertainty were 48 (4 load x 12 wind = 48 scenarios). The number of scenarios selected was heavily influenced by the solution time required for the entire one-year simulation. Tests made for a total of 48, 60, 100 and 200 scenarios indicated that the solution time grew proportionally to the number of scenarios used. The test also indicated that 60 or more scenarios became impractical for the purpose of this research due to the long solution time and because the quality of the results did not improve significantly.

Load scenarios were built using actual load and forecast load datasets. The load forecast error (LFE) was calculated as the actual load minus the forecast load. This LFE dataset contained more than a thousand different possible load scenarios, all assumed to have the same probability of occurrence. The moment matching scenario generation method proposed by Høyland et al. (2003) was used to create 50 equally-probable scenarios matching moments and correlation characteristics with the original LFE dataset. To decrease the number of load scenarios, the Dupacova et al. (2003) scenario reduction algorithm was used to select four LFE scenarios from the 50 previously selected scenarios. This scenario reduction algorithm merged two scenarios that were close enough based in their probabilistic metrics. The merged scenario contained the sum of the probability of the two original scenarios.

In the case of wind scenarios, the approach followed was a little different than the one used to represent load uncertainty. Wind behaviour can be better described using discrete Markov process as was proposed by Bathurst et al. (2002), i.e. the state of the wind (i.e. the amount of wind that can be generated) in the future can be linked with a given probability to the state of the
wind today. This vector of probabilities for each state of the wind in the future changed depending on the state of the wind today.

A dataset of estimated wind actual generation for the next four days (96 hours) was then divided into five different categories depending on the value of the actual wind generation for the first hour (or today):

- Category 1: Wind generation today is between 0% and 20% of the total installed capacity.
- Category 2: Wind generation today is greater than 20% and less or equal than 40% of the total installed capacity.
- Category 3: Wind generation today is greater than 40% and less or equal than 60% of the total installed capacity.
- Category 4: Wind generation today is greater than 60% and less or equal than 80% of the total installed capacity.
- Category 5: Wind generation today is between 80% and 100% of the total installed capacity.

For each of these categories a dataset of actual wind generation for the next four days was created, all were assumed to be equally-probable. The Dupacova et al. (2003) scenario reduction algorithm was then used to select twelve wind generation scenarios for each of these five categories.

In summary, every time the short-term model was run, a category was assigned to the actual wind for the first hour. This category was then used to select the pertaining set of wind scenarios. The load forecast error scenarios were always used regardless of the state of the load. Chapter four will provide details of the data used to build these scenarios and the scenarios generated. Figure 3.3 shows a representation of the scenario selection algorithm used for the short-term model runs.
3.4.6 **Price discount factors for day-ahead and real-time market transactions**

Many wind integration studies considered wind generation as price-taker. This assumption was mainly based on the negligible amount of wind power available relative to the total system generation installed and on the assumed perspective of the wind producer in some of the studies. As more wind generation is being installed around the world, utilities and ISOs have encouraged the study of the effect wind generation has on market prices (Jónsson et al., 2009). The approach followed in this research, to estimate the effect of wind generation over market prices, was heavily based on literary evidence and expert judgement rather than on a formal mathematical analysis due the lack of a more complete price analysis on this issue. Additional research should be conducted in the future to validate and improve the assumptions made in this work once detailed day-ahead and real-time energy prices information becomes available.
Day-ahead Market Price
Several authors have studied the effect of wind generation over day-ahead spot market prices. A recent analysis of the Nord Pool Market spot prices indicates that the effect of the forecasted wind is significant over these prices, as can be seen in Figure 3.4 (Jónsson et al., 2009). This figure shows the reduction in average spot price compared to the “no wind situation”, produced by different levels of forecasted wind power as a percentage of installed wind capacity (penetration). It can be seen that spot prices can be reduced by up to a 50% when the forecasted wind for the next day is greater than 70% of the installed wind capacity. From a system perspective the literature support the assumption that wind power significantly influences the market price of a power pool system (Jónsson et al., 2009).

Figure 3.4: Spot Price Reduction for Different Levels of Forecasted Wind
(Source: Jónsson et al., 2009.)

This same evidence can be found in other markets with significant amount of wind generation already installed. In North America, Alberta energy market prices have been also affected by wind generation, with spot price reductions up to a 25% when wind generation is blowing (Personal communication with Powerex energy traders) compared with the no wind situation. Similar effects have occurred in the Mid-C market where power trading professionals have seen
depressions on the order of about 10% below what the “without wind” expected price might be (Evans, 2009).

This research followed the approach used by Evans (2009) and applied a **day-ahead** price discount factor to day-ahead spot market price when wind was blowing. This price discount factor was scaled by the hourly wind penetration level (hourly wind generated divided by wind’s installed capacity) and then applied to the expected energy price. Price discount factors varied with the level of wind installed. These discount factors were applied both in the long-term and short-term model. Day-ahead price discounts are summarized in Section 4.1.9.

**Real-time Market Price**

In the case of intra-day and real-time markets, little research has been done to assess the impact of wind generation on these markets. The influence of wind generation on these markets would probably be significant for two reasons: First, because the lack of predictability in wind power output makes wind generation particularly difficult to trade in a spot market due to risk and penalties imposed for deviating from a contracted position (El-Sayed, 2009), as these wind power producers tend to trade wind generation mostly in real-time markets. Second, given that the introduction of wind power increases the short-term production uncertainties in the system, the real-time balancing prices would probably be heavily affected by such an introduction, which suppliers of real-time balancing power must consider in their trading and production planning (Olsson et al, 2009).

There is some evidence in today’s energy markets that wind generation is significantly affecting the typical variability of intra-day and real-time market prices. The CAISO 2009 Quarterly Report on Market Issues and Performance (CAISO, 2009) indicates that price divergence between day-ahead, hour-ahead and real-time energy markets has been significant during certain periods of time. High price volatility in the real-time market has also been observed. However, these differences have not been related to variable generation (wind, solar) in the report. In the case of the Nordic Power Pool, market data have been used to model changes in real-time market prices due the influence of wind generation, but this model has not been validated yet (Olssen et al, 2009). Power trade professionals expect to see greater real-time price variability in the Mid-C market when wind generation deviates from expected schedules (i.e. they expect to see some correlation between real-time price variability and wind forecast error). This could be significant
in this market due to the lack of geographic diversity of the wind power developments as most wind farms are currently installed in the Columbia Gorge because of favourable wind conditions (Personal communication with Powerex energy traders).

A second real-time price discount factor was then considered for transactions made on the real-time market for the short-term model. The magnitude of this price discount was set proportional to the magnitude of the wind forecast error (i.e. perfect correlation between real-time price variability and wind forecast error). When a positive wind forecast error was identified, a wind over-generation situation exists. This would produce excess wind energy; therefore causing a surplus and reducing expected market prices. On the contrary, with a negative forecast was identified, a wind under-generation situation exists, which would produce a scarcity or shortage of energy supply; therefore increasing expected market prices. Real time price discounts are also summarized in Section 4.1.11. The real time price factor method proposed did not consider the effect of load forecast error or forced outages over real-time prices.

3.4.7 Pumped-storage hydro assessment module

As was mentioned in Section 2.3.1, modern pump stations have the ability to provide different services beside water storage in a reservoir. The existence of CAISO ancillary services market and the required increment in reserves attributed to the integration of wind power in the electric system (see Section 2.1) affected the decision of allowing the pump station to provide following and regulation reserves. This technology is available today as described in Section 2.4.5.

This research modified the GOM model, proposed in section 3.4, to include an independent pump-station in the Mica – Revelstoke system. The model was modified in both the long-term and short-term model runs. The results obtained in this “Pump Case” were compared with the results of the “No Pump Case” (i.e. the model without the modifications proposed in this section) to obtain the benefit of this pump station for the BC Hydro system. The pump capacity was determined using a series of model runs for different pump capacities in order to find the most beneficial pump size. The different pump capacities analyzed were set as a function of the total installed wind capacity.
The pump station version of the proposed model included the following conditions, expressed as constraints, to allow the model to provide following and regulation reserves from a pump station:

- Following reserves can be provided whether the pump was on or off. Maximum following down reserves were provided when the pump was off and maximum following up reserves were provided when the pump was operating at maximum capacity.
- Regulation up and down reserves can be provided only if the pump was on. If the pump was on, the minimum pump level was 10% of the pump installed capacity.
- A binary variable was added to the problem to allow GOM decide whether the pump was on or off. This binary variable also allowed the model to decide when pumping was required and when pumping had to be shut down. A minimum pump load constraint was also dependent of this binary variable because when the pump was operating, the minimum pump load constraint had to be greater than 10% of the pump installed capacity. The binary variable, although useful, caused both the long-term and short-term models to become a mixed integer problems. The solution time of this model is approximately 10-20 times greater than the previous linear version of GOM.
- The load resource balance constraint was modified to include pumping as an additional BC Hydro system load (or export). The storage constraint was also modified to include an additional pumped inflow to the upper reservoir from the lower reservoir and an additional pumped outflow in the lower reservoir. The inflow matrix structure of the original GOM was maintained allowing the user to change the location of the pump station simply by changing the parameters of the incidence matrix.
- HK values (i.e. the coefficient relating power generated and flow) were assumed dependent on the forebay level of the pump station upstream reservoir; therefore, a time series data set of HK values was also introduced for the pump model.

3.5 Feasibility Analysis
A feasibility analysis was conducted to estimate the financial aspects of converting a reservoir system into a pumped-storage hydro system. This analysis used the benefits of installing the pump system as the revenues of the project. The capital cost of the facility was estimated using
available data on similar projects. Table 3.1 summarizes this information. The table shows that
the average cost of a pumped-storage hydro project is approximately US$ 990,000 per MW of
installed capacity. In the case of those projects that correspond to expansion of existing hydro
infrastructure, the average cost is approximately US$ 920,000 per MW of installed capacity. It is
the author’s opinion that this cost is more representative of future project development in BC due
to the existence of reservoirs. Therefore, the additional infrastructure required to expand the
Mica project into a pumped-storage hydro system can be narrowed to a pump station (including
the pump, mechanical/electrical equipment and civil works) and an additional pipe or tunnel to
hydraulically connect the Mica and Revelstoke reservoirs.

The feasibility analysis was done following the guidelines included in the documents
“Guidelines for the Economic Analysis of Renewable Energy Technology Applications”
prepared by the International Energy Agency (1991). Net present value, internal rate of return,
and levelised cost of energy/capacity were used as financial indicators.

The following is a list of parameters used for the financial analysis of the project.

- Revenues produced by pumped-storage hydro system.
- Capital Cost of the project (including AGC equipment) obtained from Table 3.1.
- Discount rate, annual cost of debt and taxes: a real discount rate of 7%, a cost of debt of 5.5%
  and 2010 constant U.S. dollars were used for this analysis. No taxes were considered.
- Operating and maintenance (OM) costs: These cost were fixed as 0.5% of the capital cost.
- Project lifetime: 50 years was chosen for the analysis as recommended by Deane et al.
  (2010).
- Indirect capital costs: indirect capital costs include design and engineering, contingency,
  spares, and start-up costs. For the project it was taken as 20% of direct capital cost.
- Residual value: Considered as 15% of the total capital cost.

A sensitivity analysis (i.e. increment or decrement certain key financial parameters) was also
performed for some of the financial parameters such as capital costs, project revenues and
discount rate to assess the boundaries of the financial feasibility. As part of this sensitivity
analysis, the results were also compared with the projects proposed in the BC Hydro 2008 LTAP
to compare (BC Hydro, 2008C).
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<td>KOPS II</td>
<td>Austria</td>
<td>2008</td>
<td>450</td>
<td>497</td>
<td>1.10</td>
<td>Expansion</td>
</tr>
<tr>
<td>Feldsee</td>
<td>Austria</td>
<td>2009</td>
<td>140</td>
<td>104</td>
<td>0.74</td>
<td>Expansion</td>
</tr>
<tr>
<td>Hornbergen II</td>
<td>Germany</td>
<td>2014</td>
<td>1000</td>
<td>966</td>
<td>0.97</td>
<td>Expansion</td>
</tr>
<tr>
<td>Whole EU Projects</td>
<td>EU</td>
<td>2015-2020</td>
<td>7400</td>
<td>8280</td>
<td>1.12</td>
<td>New facility and expansions</td>
</tr>
<tr>
<td>Pumped-storage US</td>
<td>USA</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Total Average (in US million per MW capacity installed) | $0.99 |
| Average of hydropower plant expansions (in US million per MW capacity installed) | $0.92 |
| P90% of expansions (in US million per MW capacity installed) | $1.20 |
| P10% of expansions (in US million per MW capacity installed) | $0.68 |

Table 3.1: Total Estimated Cost of Different Pumped-Storage Hydro Projects
4 CASE STUDY: INPUT DATA AND MODELING ASSUMPTIONS

This chapter outlines the assumptions and the input data used in this research. The first section presents the data used to characterize the BC Hydro system. The second section introduces the data and assumptions used to prepare the different wind scenarios used in this analysis. The third section details the power generation of non-wind IPPs. The fourth section describes the Market prices used in this research. The fifth section presents the details of inflows for different water years used in this research. The sixth section describes the characteristics of the pumped-storage hydro system to be installed in the Mica – Revelstoke reservoir system. The seventh section presents the different stochastic load and wind scenarios prepared for this research. Finally the eighth section provides a summary of the different optimization studies carried out in this research.

The data used in this research was prepared to describe four wind generation probably development scenarios that could materialize by the year 2027, and all the input data presented in this section reflects BC Hydro system conditions for that particular year.

4.1 The BC Hydro System

4.1.1 Load

Actual load data
BC Hydro published its latest load forecast in the 2008 LTAP (BC Hydro, 2008B). The study indicated that, without Demand Side Management (DSM), the system load for the year 2027 would be 31.5% higher than the 2008 system load (58,366 GWh/year). In other words, an additional 18,412 GWh/year of electricity will be required by the year 2027.

DSM plans, also included in the 2008 LTAP, indicated that achievable demand savings can reach up to 10,769 GWh/year by the year 2021.

The system load used in this research estimated the load condition for the year 2027 using the above mentioned forecast. An hourly time-series of actual load data for the year 2008 was scaled up to estimate the load shape in 2027 less the expected DSM. Figure 4.1 shows the daily and seasonal patterns of the estimated load data. It can be seen that load demand was the highest during winter months when more electricity will be required to support low-temperature
conditions and longer nights. On the contrary, load demand was the lowest during summer months when temperatures will be warmer and days are longer.

Forecasted load data

For short-term planning purposes, BC Hydro operation engineers usually prepare a load forecast up to seven days in advance. A set of three water years (2005, 2006, and 2007) of forecasted load was compared with actual load data available to obtain a LFE dataset for the next four days (i.e. forecast for day two, day three and day four). This dataset was used in this research to prepare load forecast scenarios as described in Section 3.4.5.

The analysis on the LFE dataset indicated that the magnitude of extreme LFE events were approximately 450, 1,000 and 1,150 MW in both directions (over-forecast and under-forecast) for days two, three and four respectively. The extreme LFE were calculated with a 99% percentile confidence interval (or 2.5 Standard Deviation reliability level). These extreme LFE events corresponded to approximately 4.5%, 10% and 11.5% of the maximum load for day two, day three and day four respectively.

The average LFE for each hour can be expressed as the percentage of the root sum square of the LFE divided by the maximum load, which is a typical unit to measure forecast performance. A
low percentage indicates a lower the forecast error, indicating a better performance of the forecasting method used. Figure 4.2 shows the performance of the LFE for the next four days. In general, the performance of the forecast decreased with the time length of the forecast period. This means that the forecast for day two was better than the forecast for day three, which was also better than the forecast for day four. The LFE was highest for morning peak hours (6-9 am) and for afternoon peaks hours (16:00 to 19:00 hrs) as shown in Figure 4.2.

![Figure 4.2: Load Forecast Performance](image)

### 4.1.2 BC Hydro generation

BC Hydro electric generation system has 30 hydroelectric facilities, one conventional gas-fired thermal plant (Burrard) and two combustion turbine generating stations (Price Rupert and Fort Nelson) that are distributed throughout the various regions of the province. The total installed generating capacity of this system is over 11,000 MW (BC Hydro, 2010).
For the purpose of this research, only five hydroelectric facilities – Mica, GM Shrum, Revelstoke, Peace Canyon and Arrow Lakes Hydro – were optimized for modeling purposes. Altogether these hydroelectric plants represent about 71% of the total system generation capacity.

Description of the optimized hydropower plants

1. **GM Shrum (GMS):** The GM Shrum powerhouse is located at the foot of WAC Bennett Dam, which impounds the Williston Lake on the Peace River. The powerhouse includes 10 generating units with a total generation capacity of 2,730 MW. The generating capacity of units 1 to 5 is 261 MW each, 275 MW for units 6 to 8, and 300 MW of generating capacity for units 9 and 10. The Williston Lake is the largest reservoir in B.C. Its surface area is about 1,773 square kilometres and it stores up to a maximum of 70,300 million cubic metres. Its storage capacity allows BC Hydro to store water inter annually.

2. **Peace Canyon (PCN):** This facility is located on the Peace River approximately 21 km downstream of the WAC Bennett Dam. The powerhouse at Peace Canyon has four generating units. The capacity of each of these units is 175 MW, which results in a total capacity of 700 MW. The Peace Canyon reservoir has a surface area of only 800 hectares and stores a maximum of 216 million cubic metres. Its storage is very limited, so under normal circumstances Peace Canyon operates almost as a run of river plant and all of the water released from the GM Shrum station is reused at Peace Canyon to generate electricity.

3. **Mica (MCA):** The Mica powerhouse at the Mica Dam that impounds the Kinbasket Lake and feeds the Columbia River. Currently this facility has four units, but two additional units have been proposed to be installed. According to the project information at the BC Hydro website (www.bchydro.com), the in-service dates for the two Mica Units are between years 2013 and 2015. The four existing units at Mica have an existing capacity of 450 MW each, and the two additional units proposed have a projected capacity of 500 MW each. This yields a total future generating capacity at Mica of 2,800 MW. The Kinbasket reservoir is 216 km long and has a licensed storage volume of 14,800 million cubic metres. Its storage capacity also allows BC Hydro to store water inter annually. Mica operation is controlled to some degree by the Columbia River Treaty between the US and Canada.

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1 Arrow Lakes Hydro is owned by Columbia Power Corporation, another Crown corporation which sales are committed in long term contracts to BC Hydro who operates this plant.
4. **Revelstoke (REV):** This facility is located on the Columbia River 130 km downstream of Mica. Its powerhouse includes five units (with an additional open bay for a future expansion), with unit 5 currently under construction. The existing capacities of units 1 through 4 are 500 MW each. The capacity of unit 5 is 505 MW. The total generating capacity at Revelstoke is 2,505 MW. Revelstoke reservoir is formed by the Revelstoke Dam. This reservoir has a surface area of 11,534 hectares and an operational storage volume of about 519 million cubic meters. Since regulated water releases from Mica provide almost three-quarters of the inflow into the reservoir, the Revelstoke power plant operates almost as a run-of-the-river plant, with normal maximum fluctuations in the reservoir level of 4.5 metres. During the freshet period the local inflows to the reservoir are high and the plant is mainly operated to pass these flows, while the Mica plant is operated at its lowest operation levels.

5. **Arrow Lakes Hydro (ARD):** Further 230 km downstream of Revelstoke is the Arrow Lakes Generating Station, which is located near the Hugh Keenleyside Dam. The total generating capacity of this plant is 192.4 MW, consisting of two units with capacities of 96.2 MW each.

**Other BC Hydro generation**

The remaining BC Hydro generation included other hydroelectric facilities known as Small Hydro, Burrard gas thermal and the ongoing and future Resource Smart projects, which primarily add generating capacity and energy to the BC Hydro system by rehabilitating and retrofitting existing generation facilities. All of this generation was modeled as a fixed input parameter in this study. Additional pre-processing prior to optimization runs was performed to generate hourly time series of energy generation from these fixed resources.

The BC Hydro other generation varied their generation by the water year modeled. Figure 4.3 shows monthly average generation for these resources. This figure indicates that the Burrard and RSP generation were higher during December and January (250 MWh) when load demand was also higher. This generation was also highest during dry water years. Small Hydro generation, on the other hand, was highest during the freshet period, when local inflows are usually high. Small hydro generation increases its output in winter period to meet loads and to pass high inflows, which can increase significantly in the geographic regions of Vancouver Island and the Lower Mainland. It can also be noted that Small Hydro generation decreases significantly during a dry
water year, with a range that varies between 450 GWh and 1,650 GWh. The Small Hydro generation during normal water years varies between 700 GWh and 1900 GWh, while during wet water years this generation varies between 1050 GWh and 2250 GWh.

![Monthly BC Hydro Other Generation](image)

**Figure 4.3: Monthly Average Generation of BC Hydro Other Generation**

### 4.1.3 Unit outage schedules for BC Hydro optimized hydropower plants
As indicated by Evans (2009), hydroelectric generating units must occasionally be removed from service for scheduled maintenance. These schedules have been determined by studies that sought to minimize the impact on the generation adequacy and market opportunities. No changes to the currently used schedules were considered when wind is integrated to the BC Hydro system, and these unit outage schedules were maintained for all of the GOM model runs.

### 4.1.4 Forebay limits and flood control curves
Reservoir boundary conditions for the GOM model were extracted from the outputs of simulation runs that contains 60 consecutive years of hydrologic data. These simulation runs were performed using a separate high-level model called HYSIM, which is a monthly time step simulation model. Forebay targets extracted from HYSIM were relaxed by +/- 2 feet to give the
GOM model flexibility to make small changes in storage levels when wind is integrated in the BC Hydro system.

Figure 4.4 shows the monthly forebay targets extracted from HYSIM for GMS, MCA and ARD. These targets represent the typical forebay variations of three of the BC Hydro modelled reservoirs and they are typically drafted through April in preparation for freshet inflows. By July, the reservoirs are quite full and store water to be used in the upcoming winter when electrical loads are high.

In the case of REV and PCN, both reservoirs have very limited reservoir storage capacity, so they were modelled using constant maximum and minimum forebay levels throughout the year, which only allowed for intra-day water storage. These forebay limits were:

- REV: Minimum forebay level 571.50 m. Maximum forebay level 572.90 m.
- PCN: Minimum forebay level 500.15 m. Maximum forebay level 502.75 m.

The Arrow Lakes and the Kinbasket reservoirs have additional constraints placed on its operation by the Columbia River Treaty, and this must maintain certain amounts of storage for flood control in the U.S. The ARD plant typically generates at full capacity all the time.
4.1.5 U.S. and Alberta interties capacity

The range of transmission intertie capacities represented the physical constraint for energy and capacity exchanges with the U.S. and Alberta. BC is interconnected with U.S. and Alberta electricity markets through the following transmission lines:

- Two 138 kV lines and one 500 kV line connecting BC to Alberta.
- Two 500 kV lines and two 230 kV lines connecting BC to the United States

According to the Approved Path Ratings with the U.S. (BCTC, 2008A), the electricity transfer limit of this intertie is 3,150 MW from Canada to U.S. and 2,000 MW from U.S. to Canada. For the interconnection with Alberta, the electricity transfer limit of this intertie is 1,000 MW in both directions (BCTC, 2008B).
Regardless of the path ratings previously mentioned, the transfer capability of both interties can change depending on the season, load level, outages, voltage instabilities and pattern of generation. To represent these variations in path ratings during the year, a time series of interties limits for exports and imports was adopted. The export intertie limit to the U.S. varied between 2,000 and 2,800 MW, while the import intertie limit varied between 1,900 and 2,000 MW. In the case of Alberta, the export intertie limit varied between 600 and 400 MW, while the import intertie limit varied between 650 and 750 MW. These intertie limits were prepared based on information provided by BC Hydro.

Additional constraints were included in the model to limit capacity exchanges (i.e. ancillary services) using the U.S. transmission tie lines, while energy transactions were allowed across both the Alberta and U.S. transmission tie lines.

### 4.1.6 Capacity reserves for load

Regulating reserve services for load were approximated at 1% of the actual hourly average load for light-load hours (0:00 to 6:00 and 22:00 to 0:00) and at 2% of actual hourly average load for heavy-load hours (6:00 to 22:00), which follows the current operation standard of the British Columbia Transmission Corporation (BCTC), which is the entity in charge of operating the electric system and maintaining its reliability (BCTC, 2007). Using these percentages, the maximum regulating reserve level for each hour of the day in an entire month was considered the necessary level of up regulating reserves to hold for load during that hour in that month. Equal quantities of down regulating reserves were also held.

Following reserves were also approximated as the maximum of the 50% of the hour-to-hour change for each month and hourly load (BCTC, 2007). An additional 2% of the load was also kept as following reserve to cover hour-ahead load forecast uncertainty.

Generation capacity for contingency reserves (i.e. reserves used to recover from unplanned outages) was also allocated for in the model. Contingency reserves were simply set at 5% of the current level of power generation (BCTC, 2007).
4.2 Wind Generation

4.2.1 Construction of wind development scenarios

For the construction of the different wind scenarios, a number of assumptions were made regarding the level of wind power penetration and geographic diversity of the wind turbines installed. This research assumed that the amount of wind turbines to be installed in BC can be significant in the next 20 years. The basis for this assumption was the significant growth of wind power generation worldwide, which is expected to continue if green energy policies are further expanded. Some regions in North-America have already seen a significant expansion of installed wind generation capacity. For example, in the last 10 years Texas has installed more than 4,000 MW of wind power, which corresponds to 8.7% of the total installed electricity generation (ERCOT, 2008). Another example of rapid growth of wind power is that of the Bonneville Power Authority (BPA) in the U.S. Northwest, which currently has 2,680 MW of installed wind capacity. Figure 4.5 shows that approximately 2,000 MW of wind power capacity has been installed at the BPA control area in the last five years.

In the case of BC, power purchase agreements between BC Hydro and IPPs were signed for 854 MW of wind power capacity. BC Hydro 2008 Call for power is currently in the process of selecting proposals for another 2,550 GWh of annual energy to be available by 2016. Assuming that 100% of BC Hydro remaining contracts of the 2008 Call for power are signed with wind IPPs, then the total capacity of wind power would be about 1,755 MW by 2016. In the same way, if another 6,000 GWh of renewable energy are requested to be available in 2027 –to meet the electricity demand growth\(^2\), it could potentially add another 2,250MW of installed wind power to the electric grid.

\(^2\) The assumption of a new call for additional 6000 GWh is based on the current electricity gap forecast included in the 2008 LTAP (BC Hydro, 2008). The LTAP indicates that a mid gap of 3,258 GWh/yr will exist by 2017 and this number can potentially increase to about 11,000 GWh/yr by the year 2027.
Therefore, a scenario of 4,000 MW of installed wind power capacity in BC by the year 2027 is considered to be possible, although unlikely. This wind generation capacity corresponds to approximately 40% of the current peak load of the BC Hydro system. This amount of wind power was considered in this study the maximum expected wind penetration level for the next 20 years.

The wind development scenarios used in this research corresponded to 10% (1,000 MW – low wind development), 20% (2,000 MW – medium low wind development), 30% (3,000 MW – medium high wind development) and 40% (4,000 MW – high wind development) of the current BC Hydro peak load. These scenarios were similar to those proposed in the Appendix F3 of the BC Hydro 2008 LTAP (Wind Integration Cost Assessment) and which was used to assess the cost of wind integration.
Regarding the geographic diversity of each wind penetration level, the literature indicates that the error of a regional wind generation forecast is expected to decrease due to spatial smoothing (Focken et al., 2002). This means that as more geographically diverse wind turbines are installed the variability of wind and the wind forecast error will decrease. To isolate any geographic diversity effect on the impacts of the proposed wind development scenarios, this research assumed that the four wind scenarios had the same geographic diversity.

BC Hydro’s Wind Data Study identified four regions where wind power can be developed. Table 4.1 summarizes the number of projects identified in each region and the capacity factor range for these projects. The Peace Region has the highest number of theoretical wind projects and the highest capacity factor range. Indeed, most of the awarded contracts to IPPs in the 2006 and 2008 Calls for power were located in this region. Therefore, it was assumed that a preference for projects located on the Peace Region will continue. Then, each wind penetration level scenario included 70% of its projects in the Peace Region while the remaining 30% was equally divided between Vancouver Island, North Coast and Southern Interior.

<table>
<thead>
<tr>
<th>Region</th>
<th>Number of Projects</th>
<th>Total Installed Capacity (MW)</th>
<th>Capacity Factor Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vancouver Island</td>
<td>14</td>
<td>1,421</td>
<td>20% to 34%</td>
</tr>
<tr>
<td>North Coast</td>
<td>12</td>
<td>4,211</td>
<td>20% to 34%</td>
</tr>
<tr>
<td>Southern Interior</td>
<td>30</td>
<td>4,154</td>
<td>19% to 31%</td>
</tr>
<tr>
<td>Peace</td>
<td>48</td>
<td>6,113</td>
<td>20% to 41%</td>
</tr>
</tbody>
</table>

Table 4.1: Installed Capacity and Capacity Factor for Theoretical Wind Projects
(Source: Adapted from DNV-GEC, 2009).

### 4.2.2 Actual wind generation data

Wind energy datasets used in this research were obtained from the BC Hydro Wind Data Study (DNV-GEC, 2009) which provided BC Hydro with 10 years of simulated 10-minute actual wind generation time series for different potential wind farm sites across BC and three years of simulated hourly Numerical Weather Prediction (NWP) forecast wind generation time series. Three simulated hourly wind data sets for years 2005, 2006 and 2007 were used in this research.
The following figures show the simulated generation of the proposed wind scenarios from two different perspectives. Figure 4.6 displays the series of one-hour wind power values for each wind scenario, which is an indicator of the wind generation variability. Figure 4.7 displays the 30-day rolling average, which is an indicator of the wind generation seasonal characteristics. It can be seen from these figures that wind generation in BC varies seasonally and it is highest in winter with less variability while it is low in summer and its variability is high.

Figure 4.6: Hourly Variability of Wind Generation Scenarios. Water Year 06/07
4.2.3 Forecasted wind generation data

As was mentioned earlier the wind NWP forecast data was simulated using a mesoscale NWP model. This model was run once a day to generate four days (96 hours) of forecasted wind. The forecasted hourly wind data sets for the years 2005, 2006 and 2007 was available for this study and it is described in this section to show the performance of day-ahead wind forecast error. As described in Section 3.4.5, only actual wind data was used to create the different stochastic wind scenarios used in the short-term model included in this study.

Table 4.2 show extreme day-ahead WFE events for the different wind scenarios used in this study, with a +/- 2.5 Standard Deviation reliability level. The WFE value is positive when the actual wind was greater than the forecasted wind or over-generation, and is negative when the actual wind was lower than the wind forecasted or under-generation. The results indicates that, for wind forecasts prepared 25 – 48 hrs in advance, extreme WFE are approximately 28% of the installed wind capacity for wind over-generation events and 37% of the installed wind capacity for wind under-generation events.
Table 4.2: Summary of Extreme WFE Events for Different Wind Scenarios

<table>
<thead>
<tr>
<th>Wind Scenario</th>
<th>Wind Over-generation</th>
<th>Wind Under-generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>10% Penetration</td>
<td>276 (MW) 26% (%)</td>
<td>-342 (MW) -32% (%)</td>
</tr>
<tr>
<td>20% Penetration</td>
<td>572 (MW) 29% (%)</td>
<td>-754 (MW) -38% (%)</td>
</tr>
<tr>
<td>30% Penetration</td>
<td>839 (MW) 28% (%)</td>
<td>-1106 (MW) -37% (%)</td>
</tr>
<tr>
<td>40% Penetration</td>
<td>1061 (MW) 28% (%)</td>
<td>-1476 (MW) -37% (%)</td>
</tr>
</tbody>
</table>

Although the magnitude of extreme wind day-ahead events was comparable to the magnitude of the LFE, the performance of the load forecast was much better than the day-ahead forecast for wind. Figure 4.8 shows the forecast performance for the different wind scenarios measured as the root sum square of the WFE divided by the installed wind capacity. It can be seen that the forecast performance for the four wind scenarios was quite similar, with this performance increasing from a range of 10% to 14%. The performance of the forecast decreased with increasing forecast time (i.e. the forecast prepared 25 hours in advance performed better than the forecast for prepared 48 hours in advance).

Figure 4.8: Performance of Wind Forecast Compared with Load Forecast
4.2.4 Capacity reserves for wind

The magnitude of reserves to be allocated for dealing with the intrinsic variability of wind has been studied by several researches and can be found in the literature. The approach followed in this research provided an adequate estimate given the data available.

Wind power incremental reserves for regulation and load following were estimated using information of different wind integration studies, as summarized in Figure 4.9. The figure shows that incremental reserves for wind were proportional to the total installed capacity of wind generation. Incremental reserves also varied between balancing systems.

BC Hydro is currently preparing a wind integration study for potential wind power projects in BC. Preliminary information provided by BC Hydro Generation Resource Management indicated that, for 15% - 35% wind penetration, the total amount of incremental reserves for wind generation vary between 5% and 10% of the installed wind capacity.

Table 4.3 summarizes estimated incremental wind reserves. Wind power’s regulating reserves were approximated from +/- 2.5% of installed capacity for all hours in the year for 10% wind penetration to +/- 1.8% of installed capacity for 40% wind penetration. Wind power’s following reserves were calculated in the same way as the load following reserves, but considering 10% instead of 2% for wind hour-ahead uncertainty. The incremental wind reserves correspond to the
difference between the root sum square of the following load reserves and the following wind reserves, and the following load reserves. It can be seen that the magnitude of these reserves was in the range of incremental reserves for wind power cited in the literature. Figure 4.10 also shows the variation of the average hourly following reserves for load and the incremental wind following reserves. It can be seen that during the load morning peak (i.e. HE 6 to HE 9), wind generation usually ramps down, and then less wind following up reserves and more wind following down reserves are required.

<table>
<thead>
<tr>
<th>Wind Penetration (%)</th>
<th>Regulating Reserves (MW)</th>
<th>Following Reserves (MW)</th>
<th>Total Wind Incremental Reserves (MW)</th>
<th>% Installed Wind Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>25</td>
<td>25</td>
<td>50</td>
<td>5.0%</td>
</tr>
<tr>
<td>20</td>
<td>44</td>
<td>78</td>
<td>122</td>
<td>6.1%</td>
</tr>
<tr>
<td>30</td>
<td>60</td>
<td>136</td>
<td>196</td>
<td>6.5%</td>
</tr>
<tr>
<td>40</td>
<td>72</td>
<td>218</td>
<td>290</td>
<td>7.3%</td>
</tr>
</tbody>
</table>

Table 4.3: Estimated Average Wind Incremental Reserves

Figure 4.10: Average Hourly Following Reserves
4.3 Other IPP Generation

Generation provided by IPPs with an energy source different from wind (run-of-river, biomass) required careful consideration in this analysis. First, IPP generation was divided in two categories:

- **Actual IPP Generation** currently provided or acquired by BC Hydro (including Open Call for Power 2006, Rio Tinto Alcan hydro generation and others IPP’s).
- **Future IPP Generation** to be provided by the Clean Power Call 2008 and other futures calls for power, not including future wind power projects.

Actual IPP Generation was modelled using existing IPP projects information, including energy purchases from the Rio Tinto Alcan project (ALCAN). This generation was also modelled as an input parameter. Historic energy profiles of the existing IPPs were used to create monthly energy shapes. Actual IPP generation varied by month and it did not vary by the water year.

Future IPP Generation did not include wind power in its portfolio. The amount of generation included in this parameter varied depending of the wind scenario considered in the analysis. Under the assumption that 11,000 GWh/yr of power will be required by the year 2027 (energy gap), the amount of future IPP Generation was estimated as the total energy required by 2027 minus the power included in the wind scenario considered.

Figure 4.11 shows a summary of the monthly average power delivered by IPPs. Actual IPP and Future IPP generation peaks in the freshet, due to run-of-river projects included in these portfolios. As expected, future IPP generation decreases when wind generation increases. No future IPP generation is required for the wind 40% penetration scenario because the energy provided by this wind scenario is sufficient to cover the projected energy gap. In BC, wind generation compliments run-of-river based generation because, as shown in Figures 4.6 and 4.7, wind generation peaks in winter while run-of-river peaks in summer, thus creating a more regular combined generation output across the whole year.
4.4 Market Prices

4.4.1 Energy prices

Obtaining representative energy prices from the Northwest electricity market can be difficult because much of the BC Hydro and Powerex price data remain confidential. Therefore, an hourly base price data set was built for this research using energy prices for the mid-Columbia (Mid-C) market as a reference. This base price data set was used for energy transactions for both the Alberta and the U.S markets.

The forecasted annual Mid-C average energy price for year 2027 was obtained from the BC Hydro LTAP 2008 (BC Hydro, 2008B). This study estimated an annual average price of 62 CAD$/MWh (approximately 56 US$/MWh) for the year 2027. The annual average energy price was multiplied by a typical hourly price shape factor to calculate the hourly base price data set.

Figure 4.12 shows the variability of the estimated hourly and daily base energy prices for year 2027. The greatest variability can be observed in hourly energy prices.
This research required a set of day-ahead (DA) and a set of real-time (RT) energy prices. Over the long term, both prices should converge to the same annual energy price. The only difference that exists is in the short-term variability of both prices which can be significant in some instances.

Discount factors were applied to the base energy price dataset to estimate DA and RT energy prices. Their calculations are explained in the section below.

### 4.4.2 Discounts factors for energy prices

As indicated in Section 3.4.6, energy market prices are influenced by significant amounts of wind generation due to its very low marginal cost compared with other generation alternatives (Jónsson et al., 2009). The discount factors proposed are aimed to simulate this effect in the model.

For the DA market, a discount factor was used for periods when more wind power shows up than the expected. This price discount factor was scaled by the hourly wind penetration and then was
applied to the expected energy price. For example, if a discount factor of 10% is applied, then when wind power is at its maximum level, a 10% discount is applied to the energy market price. If wind is blowing at only half of the total installed capacity then a 5% discount is applied to the energy market price.

The RT price discount factor used caused prices to increase or to decrease in order to represent the expected increased volatility of these prices due to wind generation. It was assumed that this price factor is proportional to the wind forecast error of the installed wind generation in BC. When more wind shows up (wind over-generation), RT energy prices were lower than DA energy prices due to excess wind generation that is made available in the RT market. When less wind shows up (wind under-generation), RT energy prices were higher than day-ahead energy prices due the assumed lack of generation available in the market. The RT price discount factor was scaled by the hourly wind forecast error, calculated as the hourly wind forecast error divided by wind’s estimated extreme forecast error, and then it was applied to the expected DA energy price to calculate RT prices. Table 4.4 summarizes the discount factors used in this research for different wind penetration levels.

<table>
<thead>
<tr>
<th>Wind Penetration (%)</th>
<th>DA Discount Factor (%)</th>
<th>RT price factor wind Over-generation (%)</th>
<th>RT price factor wind Under-generation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>10%</td>
<td>75%</td>
<td>122%</td>
</tr>
<tr>
<td>20</td>
<td>20%</td>
<td>55%</td>
<td>127%</td>
</tr>
<tr>
<td>30</td>
<td>30%</td>
<td>40%</td>
<td>139%</td>
</tr>
<tr>
<td>40</td>
<td>40%</td>
<td>25%</td>
<td>145%</td>
</tr>
</tbody>
</table>

Table 4.4: Proposed Discount Factor for DA and RT Market Prices

In summary, the day-ahead and real-time energy prices were estimated as follows:

- DA energy price = base energy price x DA discount factor.
- RT energy price = base energy price x DA discount factor x RT discount factor.

It is important to note that in the long term both set of prices, RT and DA, converge to the same annual energy price.
4.4.3 Ancillary services prices

Ancillary service prices for operating reserves and contingency reserves were included in this research to assess the value of unused capacity available in the optimized plants of the BC Hydro system.

CAISO day-ahead market clearing prices for regulating up, regulating down, and spinning reserves for the water year (2007/08) were used because they were considered to represent the ancillary service market prices in the U.S. Northwest region. This data was obtained from the CAISO website and also used by Evans (2009). It should be noted that average annual ancillary service prices were comparable to current contracts in this region.

Figure 4.13 shows CAISO hourly clearing prices for three types of reserves. In general ancillary service prices were lower than energy market prices.

![Figure 4.13: CAISO Ancillary Services Prices for Water Year 2007/08](Source: Adapted from Evans, 2009).
4.5 Selection of Water Years and Correlation with Wind Years

In typical generation planning studies in B.C., the series of water years from 1964 to 1973 are used because they have been shown by BC Hydro planners to represent dry, average, and wet years in the Pacific Northwest. To limit the number of study iterations in this research; three representative water years representing wet, average, and dry years from the above ten water years were chosen to explore the sensitivity to different inflow conditions of both wind integration cost and pumped-storage hydro benefits. Classification of wet, average, and dry followed the one proposed by Evans (2009), which accounts for the inflows to the BC Hydro reservoirs as well as the measured river flows at the Dalles Dam near the mouth of the Columbia River.

Figure 4.14 shows the cumulative inflows to the five modeled hydropower plants for the entire water year. The water years used in this research were 1969/70 representing a dry year, 1968/69 as an average year, and 1973/74 to represent a wet year.

![Figure 4.14: Cumulative Inflows for Ten Water Years](Image)

(Source: Adapted from Evans, 2009).
Inter-annual variation of wind generation, on the other hand, was much lower than the variation in water volume. Table 4.5 shows the annual wind generation for different wind penetration scenarios. The wind generation inter-annual variation was approximately 5% between the least windy and most windy year, while the inter-annual variation of annual water volume was approximately 20% between the selected dry and wet water years.

<table>
<thead>
<tr>
<th>Wind Penetration (%)</th>
<th>Annual Wind Generation in GWh (% relative the average for three years)</th>
<th>Water Year 2005/2006</th>
<th>Water Year 2006/2007</th>
<th>Water Year 2007/2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>2,735 (96%)</td>
<td>2,920 (103%)</td>
<td>2,862 (101%)</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>5,890 (97%)</td>
<td>6,275 (103%)</td>
<td>6,108 (100%)</td>
<td></td>
</tr>
<tr>
<td>30</td>
<td>8,137 (96%)</td>
<td>8,710 (103%)</td>
<td>8,510 (101%)</td>
<td></td>
</tr>
<tr>
<td>40</td>
<td>11,163 (98%)</td>
<td>11,704 (102%)</td>
<td>11,406 (100%)</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.5: Annual Wind Generation for Different Wind Scenarios

Considering that wind generation represented between 3% (10% wind penetration) and 14% (40% of wind penetration) of the total electric generation, it can be assumed that the inter-annual variation of wind generation had little effect on the hydro generation patterns. Therefore it was assumed that, the combination of different wind and water years will have no significant impacts on the results of this research.

4.6 Mica-Revelstoke Pump Station

This research assumed that the installed capacity of the Mica pump-station installed pump capacity will vary with amount of wind penetration; therefore, the pump capacity was expressed as percentage (%) of installed wind capacity. A number of runs were done to identify which pump capacity represents the optimum capacity. Ten different pump/wind capacity ratios were tested, ranging from 10% to 60% in 10% increments.

The characteristics of the pump station are summarized in Table 4.6. A single monthly flow to energy ratio (HK) was used in this research, which assumes that the water pumped from the Revelstoke reservoir to the Mica reservoir consumes the same amount of energy regardless of the reservoir forebays variation during the month. The reason for this assumption was that the possible variation of head due to changes in forebay during a single month (approximately 15m
variation of a total head of 180m) is less than 10% and can be neglected for the purposes of this research.

No downstream forebay limits were included for the operation of the pump because changes in forebay levels in the Revelstoke reservoir were already limited in the model (only 1.5 m of forebay variation allowed). The pump station can operate under this range of forebay without risk of cavitation.

The minimum flow allowed for operating the pump station was established at 10% of the installed pump capacity, which represents a reasonable limit as found in the literature (Karassik et al., 2008).

<table>
<thead>
<tr>
<th>Pump Station Characteristics</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Pump</td>
<td>Variable speed with AGC capacity for load regulation</td>
</tr>
<tr>
<td>Installed Pump Capacity</td>
<td>10% - 60% of installed wind generation</td>
</tr>
<tr>
<td>Minimum Pump Level</td>
<td>10% of installed pump capacity</td>
</tr>
<tr>
<td>Flow to Power Ratio (Hk)</td>
<td>Variable, 1.384 (May) – 1.705 (Sep)</td>
</tr>
<tr>
<td>Wire to wire efficiency</td>
<td>80% - 82%</td>
</tr>
</tbody>
</table>

Table 4.6: Summary of Pump Station Characteristics

4.7 Stochastic Load and Wind Scenarios

As indicated in Section 3.4.5, four load and twelve wind scenarios were created to represent load and wind uncertainty. These scenarios used the LFE dataset and an actual wind dataset as the base information for the analysis. Each scenario created included a 72-hr long time-series to represent forecast information prepared from 25 to 96 hrs in advance.

In the case of the load scenarios, a LFE dataset consisting of 1,000 sequences was used to prepare four representative load scenarios. Figure 4.15 shows the selected LFE scenarios applied over an actual load set. The green line represents the most probable scenario (97%). The average LFE in this case was 19 MW. The blue lines represent the extreme-case scenarios, each with a small chance of occurrence (1%). Their extreme values were equal to the extreme events outlined in Section 4.1.1. The selection of a small number of load scenarios was justified by the relatively good performance of the load forecast as was showed in Figure 4.8.
In the case of wind scenarios, a dataset of wind actual generation was grouped into five categories according to the state of the wind in hour one, or the actual wind generation when the forecast was prepared. For each of these categories, twelve wind scenarios were selected. This process was repeated for each of the wind penetration levels studied. Figure 4.16 shows the different stochastic wind scenarios prepared for Wind Penetration 20%. It can be seen that there were differences in both the shape and the probability of the wind scenarios for each category. For example, for Category 1 and Category 2 the wind scenarios have a high probability to be at generation levels lower than 800 MW while for the rest of the Categories the wind scenarios have a high probability to be at generation levels between 500 MW and 1,500 MW.
Figure 4.16: Stochastic Wind Scenarios
4.8 Summary Scenarios Modeled

Figure 4.15 summarizes the case studies considered to perform runs of the long-term studies. The boxes outlined in black represent the different characteristics of each case study, while the green boxes represent the outcomes of the comparison of the different runs considered in each study. In total, 72 runs were made for the long-term studies.

Figure 4.17: Long-term Model Scenarios

Figure 4.16 summarizes the case studies considered in the short-term studies. Only one water/wind year scenario was considered for the version of the model with Pumped-storage hydro operation because the solution time of this model was extremely long and was beyond reasonable waiting times (it took approximately five days per study). In total, 32 runs were made using the short-term model. Each daily run was repeated for the entire year (365 daily runs for one year), which in total represented 11,680 runs. The results from these runs were used to estimate the benefits of installing a pumped-storage unit at Mica and allowed the assessment of the scheduling cost of wind, as will be presented and discussed in Chapter five.

Figure 4.18: Case Studies Short-Term Model
5 RESULTS AND ANALYSIS

In this chapter, the results of this research are presented and analyzed. The first section of this chapter discusses how the size of the pump station was selected in order to obtain a more cost-efficient pumped-storage system to manage the variability of wind power. Then, the economic benefits obtained from the pumped-storage system proposed and the variation of the benefits with the different services provided by this system. The third section presents the effects of the pumped-storage system on wind integration impacts. Section four compares the hourly and seasonal operation patterns of the pumped-storage system. The fifth section presents the effects of the pumped-storage system on the Kinbasket and Williston Lakes storage patterns. The sixth section outlines the effects of this system on the amount of water spills from the optimized hydropower plants. The seventh section presents the changes in energy trade that could be attributed to the pumped-storage system. Finally, the results of the financial feasibility analysis are presented and discussed in section eight.

5.1 Selection of the Pumped-Storage Hydro System Pump Capacity

A series of runs were prepared to select the most adequate size of the pump station with respect to the wind power installed capacity. To simplify this analysis, the infrastructure and site constraints for the pump station size were neglected in this research. A cost-benefit ratio analysis was prepared for the 20% wind penetration scenario for different pump station sizes. Cost-benefit analysis is a simple method to compare different alternatives when financial conditions are similar. The lower the cost-benefit ratio, the more convenient the project is.

The capital costs were obtained by multiplying the capacity of the pump station by the average cost of expanding a hydropower plant to a pumped-storage system shown in Table 3.1. Several optimization runs to simulate the operation of the BC Hydro’s system hourly operation for one year, with and without the pumped-storage hydro system were carried out and the results were compared to estimate the benefits of the pump-storage system. Table 5.1 lists the results of the runs and the cost-benefit ratios obtained for different pump station sizes.
The results showed that for 20% wind penetration level, lower cost-benefit ratios could be obtained for a pumped-storage system with an installed pump capacity between 200MW and 400MW (10% and 20% of the installed wind capacity respectively). Therefore, a pump station size equivalent to 15% of the installed wind capacity was selected as the preferred option for the purposes of this study.

### 5.2 Economic Benefits of the Pumped-Storage Hydro System

The annual benefits of the Mica Pumped-storage system were obtained by comparing the results of different case studies outlined in Figure 4.15. Table 5.2 summarizes the annual economic benefits for this pumped-storage system. Figure 5.1 shows the variation of these benefits for different wind penetration scenarios. It can be seen that, in general, the benefit of the pumped-storage system increased when wind penetration increased and when more water was available in the BC Hydro system (i.e. wet water years produce more benefits than dry water years).

<table>
<thead>
<tr>
<th>Water Year</th>
<th>Pump Capacity Installed</th>
<th>Wind 10% Penetration</th>
<th>Wind 20% Penetration</th>
<th>Wind 30% Penetration</th>
<th>Wind 40% Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal</td>
<td>150 MW</td>
<td>11.62</td>
<td>22.28</td>
<td>31.99</td>
<td>44.62</td>
</tr>
<tr>
<td>Dry</td>
<td>300 MW</td>
<td>9.49</td>
<td>18.53</td>
<td>27.24</td>
<td>40.28</td>
</tr>
<tr>
<td>Wet</td>
<td>450 MW</td>
<td>11.42</td>
<td>23.62</td>
<td>36.67</td>
<td>51.22</td>
</tr>
<tr>
<td></td>
<td>600 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 5.2: Annual Benefits of the Mica Pumped-Storage System, in Million US$**
The economic benefits of the pumped-storage system were obtained from the provision of the following services:

- Additional revenues from energy trade in the Mid-C and Alberta market (shift energy).
- Provision of AGC capacity used for regulation by other utilities or generators.
- Provision of Non-AGC capacity used for spinning reserves by others utilities or generators.
- Storage of freshet Revelstoke inflows in the Kinbasket Reservoirs.

Figure 5.2 shows the distribution of the annual benefits of the Mica pumped-storage system. It can be observed that wind penetration did not produce a significant variation in the distribution of the pumped-storage benefits. The distribution of the economic benefits varied significantly within the water years analyzed. The analysis show that during normal water years, approximately 35% of the revenues were obtained from shift energy, 23% were obtained from provision of AGC capacity and the remaining 42% were obtained from provision of non-AGC capacity. In the case of dry water years, these benefits were: shift energy 41%, provision of AGC capacity 8% and provision of non-AGC capacity 51%. Finally, during wet years only 6% of the benefits were obtained from energy shift while provision of AGC and non-AGC capacity produced 50% and 44% of the benefits respectively.
<table>
<thead>
<tr>
<th></th>
<th>Normal Water Year 1968</th>
<th>Dry Water Year 1969</th>
<th>Wet Water Year 1973</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wind 10% Penetration</strong></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
</tr>
<tr>
<td>Energy Arbitrage</td>
<td>40%</td>
<td>52%</td>
<td>41%</td>
</tr>
<tr>
<td>Slack Capacity AGC</td>
<td>39%</td>
<td>42%</td>
<td>69%</td>
</tr>
<tr>
<td>Slack Capacity NON_AGC</td>
<td>21%</td>
<td>6%</td>
<td>2%</td>
</tr>
<tr>
<td><strong>Wind 20% Penetration</strong></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
</tr>
<tr>
<td>Energy Arbitrage</td>
<td>42%</td>
<td>52%</td>
<td>45%</td>
</tr>
<tr>
<td>Slack Capacity AGC</td>
<td>36%</td>
<td>41%</td>
<td>6%</td>
</tr>
<tr>
<td>Slack Capacity NON_AGC</td>
<td>22%</td>
<td>7%</td>
<td>49%</td>
</tr>
<tr>
<td><strong>Wind 30% Penetration</strong></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
</tr>
<tr>
<td>Energy Arbitrage</td>
<td>45%</td>
<td>53%</td>
<td>42%</td>
</tr>
<tr>
<td>Slack Capacity AGC</td>
<td>32%</td>
<td>38%</td>
<td>8%</td>
</tr>
<tr>
<td>Slack Capacity NON_AGC</td>
<td>23%</td>
<td>9%</td>
<td>50%</td>
</tr>
<tr>
<td><strong>Wind 40% Penetration</strong></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
<td><a href="#">Diagram</a></td>
</tr>
<tr>
<td>Energy Arbitrage</td>
<td>42%</td>
<td>50%</td>
<td>42%</td>
</tr>
<tr>
<td>Slack Capacity AGC</td>
<td>32%</td>
<td>42%</td>
<td>8%</td>
</tr>
<tr>
<td>Slack Capacity NON_AGC</td>
<td>26%</td>
<td>8%</td>
<td>53%</td>
</tr>
</tbody>
</table>

Figure 5.2: Benefits Distribution of Mica Pumped-Storage System
5.3 **Effects of the Pumped-Storage Hydro System on Wind Integration Costs**

The effects of the pumped-storage system on incremental wind reserves costs and scheduling costs were studied and are presented in detail in the following sub-sections. It can be stated that overall, the wind integration costs decreased when the pumped-storage system is integrated in the BC Hydro system.

### 5.3.1 Incremental wind reserves costs

Figure 5.3 shows the variation of incremental wind reserves costs for different wind penetration, water year and use of the pumped-storage system. In general, the cost of incremental wind reserves increased when wind penetration increased, regardless of the water year and the use of the pumped-storage system. These costs varied from US$ 4.16 to US$ 5.58 per MWh of wind generated for the BC Hydro system without pumped-storage and from US$ 3.97 to US$ 5.19 per MWh of wind generated when the pumped-storage system was included. Out of the three water years analyzed, the wet water year showed lower costs than the normal water year, which had also lower costs than the dry water year.

The pumped-storage system effectively reduced incremental wind reserves costs and this reduction was more significant when more wind was integrated. This cost reduction was on average 4%, 6%, 8% and 9% for a wind penetration of 10%, 20%, 30% and 40% respectively. This effect could be due to a higher availability of unused slack up and down capacity in the BC Hydro system. This additional regulation and flexibility capability could then be used to provide required incremental wind reserves and ancillary services to other utilities.

It can also be observed in Figure 5.3 that the incremental wind reserve costs were more effectively reduced during wet water years than during normal or dry water years. This could be attributed to the fact that during wet water years the pumped-storage system provided less energy shift benefits (see for example in Figure 5.2 that only 2%-6% of the pumped-storage system benefits corresponded to energy shift), thus the available capacity of the pumped-storage system could be better used to provide regulation and following reserves for the wind generation.
5.3.2 Scheduling costs

Figure 5.4 shows the scheduling costs estimated for the BC Hydro system with and without the pumped-storage system during a normal water year. It can be noted that, surprisingly, the scheduling costs decreased with increasing wind penetration levels. This cost was also lower when the pumped-storage system was included in the BC Hydro system. However, the ability of the pumped-storage system to reduce the scheduling costs also decreased with increasing wind penetration levels. This could be explained by the fact that much of the benefits of this pumped-storage system were primarily used or allocated to provide incremental regulating and following reserves for wind, thus reducing the benefits of managing day-ahead wind forecast error.
Figure 5.4: Scheduling Costs with and without Pumped-Storage System

The variation of the scheduling costs with water years was studied only for the base BC Hydro system without the pumped-storage system. Figure 5.5 shows the variation of scheduling costs in normal, wet and dry water years. It can be seen that dry water years had lower scheduling costs than normal and wet water years. This could be attributed to the fact that during dry water years, less energy transactions were made and less market opportunities were foregone. On the contrary, during wet water years more energy transactions were made, which could lead to more foregone market opportunities as more wind power is integrated.

A number of run for the normal water year were prepared to study the effect of considering the load forecast error on scheduling costs. These runs did not include the load stochastic scenarios as was described in Section 3.4.5, and only the twelve stochastic wind scenarios were modeled. Figure 5.6 shows the results of these runs for the BC Hydro system without including the pumped-storage system. It can be observed that scheduling costs were higher when only the wind scenarios were considered in the modeling. This means that the load forecast error could partially reduce contribute to the scheduling cost of the day-ahead export/import schedules by approximately 20%.
Figure 5.5: Variation of Scheduling Costs without Pumped-Storage System for Different Water Years

Figure 5.6: Effect of Load Forecast Error on the Scheduling Cost

5.3.3 Summary

The total incremental wind reserves and scheduling costs and their distribution are summarized in Figure 5.7. It can be noted that the costs of wind integration were higher for 10% and 40% wind penetration but were lower for 20% and 30% wind penetration levels. These cost variations could be attributed to the distribution of the wind energy scenarios used in this analysis as
illustrated in Figure 4.11, wind generation in these scenarios complements run-of-river generation and their combined energy output was more uniform throughout the year, which could help in the operation and optimization of the BC Hydro resources. In this study, the most diverse IPP energy portfolio corresponded to the 20% wind penetration scenario, which also had the lowest wind integration costs.

The pumped-storage hydro system reduces wind integration costs for all wind penetration scenarios by approximately 10% or US$ 0.75 per MW of wind generated. Incremental wind reserves costs were the most significant cost component and they ranged between 60% and 80% of the total cost. The significance of their cost contribution increased as the wind penetration increased.

Figure 5.7: Total Estimated Wind Integration Costs

Note: PSH means Pumped-storage hydro system.
5.4 Operation Patterns of the Pump Station Facility

In general the operation pattern of the pump station did not change for different wind penetrations levels. In nearly all cases, increasing the wind energy penetration simply resulted in an increase in the magnitude of pumping.

Figure 5.8 shows the average hourly variation of the pump energy used to pump and store water in the Kinbasket Lake. In general, the pump operated during light-load hours (22:00 hrs to 6:00 hrs), storing low-valued energy in the system for use during high-load hours (6:00 hrs to 22:00 hrs) the load is high.

The pump station was operated differently depending on the water year. During dry and normal water years, a seasonal difference was detected in the operation of the pump station; in effect, the pump station was used more during the freshet-summer period (April to September) than during the fall-winter period (October to March). During freshet-summer period, the pump station operated about 60% of the installed capacity during light-load hours, while during the fall-winter the pump station only operated about 22% of the installed capacity. This difference could be closely correlated with the Revelstoke inflows during the freshet and summer period and decreases during the winter.

In the case of the pump station operation during the wet water year (1973), the facility stored less energy in the freshet-summer season than during normal and dry water years (only 10% of installed pump capacity), but it slightly stored more water during the fall-winter season (25% of installed pump capacity) as shown in Figure 5.8. The reason for this operating pattern could be attributed to the fact that much more water was available during freshet that could not be stored due to reservoir capacity constraints. During the fall-winter season, on the other hand, low inflows in the previous water year (1972) resulted in an increase in pump use to store water in early winter and this shows that the pump station can be a useful tool for shaping the energy production in times when additional water in storage is needed.
Figure 5.8: Hourly Variation of Average Pumped Energy
Regarding the amount of reserves (regulation and following) that was provided by the pump station, the results did not vary significantly for different wind penetration and water years used in this study. Figure 5.9 shows the average hourly reserves provided by the pump station expressed as a percentage of the total incremental wind reserves required. It can be seen that the pump station provided a significant portion of following down reserves and regulation down reserves. These reserves were available when the pump station was either operating at minimum or maximum pump levels. The pump station provided nearly all of the incremental following down reserves required for wind integration, particularly at the end of the day (Hour ending 22 and 23). Consequently, almost no following up reserves were needed to be provided by other facilities. In the case of regulation down reserves, those were significant during light-load hours and during the morning peak hours, with an average of 20% of the reserves required for wind integration for this period. On the other hand, regulation up reserves accounted for just about 3% of the total incremental wind regulation reserves required, which were provided particularly during light-load hours.

Figure 5.9: Average Hourly Variation of Capacity Reserves Provided by Pump Station
5.5 Modifications to Reservoirs Storage Patterns

The two reservoirs with appreciable storage in the BC Hydro system are the Kinbasket Lake above Mica generating station and the Williston Lake above GM Shrum generating station. The analysis was limited to these two reservoirs because they were the most likely reservoirs where wind-displaced and pump-displaced energy could be stored and/or used to maximize the value of resources. Most trends in the operation of these two reservoirs were consistent with the wind penetration levels studied.

The effects of the Mica pumped-storage system on the reservoir storage patterns of the Williston Lake was negligible. These effects were different, however, in the case of the Kinbasket Lake. Figure 5.10 shows the changes in storage for this reservoir when the pumped-storage system was added. Basically, the pattern shows that more water is stored during late spring and summer to optimize the operation of this system. This effect was also proportional with the level of wind penetration and the capacity of the pumped-storage system, which means that when more wind generation and pump capacity were available, more water was stored in the Kinbasket Lake during the freshet period. It can also be seen that the effect of the pump is more significant during the normal water year case than in dry and wet water year cases. This could be attributed to with the fact that during dry water years, the relative scarcity of water resulted in lower overall inflows and storage, while during wet water years the Kinbasket Lake was already at a very high forebay level during summer, therefore, not much storage volume will be available to store more water using the pumped-storage system.

Smaller and sharper changes in Kinbasket Lake storage also occurred during the winter and early spring periods. These changes can be attributed to market opportunities for exporting and importing energy that could be better shaped, shifted and exploited with the pumped-storage system.
Figure 5.10: Storage Reservoir Changes in Kinbasket Lake
5.6 Analysis of Hydropower Plant Spills

The amount of water spilled for all model runs was tabulated. Nearly all of the spills were at the ARD on the Columbia River, and they were driven by minimum flow requirements dictated by the Columbia River Treaty. When adding the Mica pumped-storage system, the variation of the total volume of spilled water was not significant. In a normal water year the volume of spilled water was increased by approximately 0.1% for all wind penetration levels studied. For the dry water year runs the spilled water volume increased approximately 0.5%, while for wet water years the spilled water volume remained constant.

Although the incremental spilled volume was not significant, the model did change the annual spill patterns (with exception of the wet water year). Figure 5.11 shows the difference between the base case (without pumped-storage system) and the Mica pumped-storage case. The figure indicates that during the normal water year, water spills decreased during the freshet period and then were increased in late summer. This could be attributed to the fact that a preset target storage level had to be achieved at the end of the year studied. Then, water savings made during freshet could have been used in late summer because the reservoirs were above the target storage level.

The case for the dry water year was different. Water spilled with the pumped-storage system included increased in March and late summer. The first water spill increment can be attributed to the low energy market prices that typically occur during this period, while the second one can be attributed to the fact that water saved during the freshet had to be released at the end of the planning period to achieve the target storage levels.

Different wind penetration levels did result in significant differences in the magnitude of the spill patterns in normal and dry years. It seems that if the energy portfolio contained more wind then more water spills can be saved during freshet period, because wind generation peak during winter in contrast to run-of-river generation which peaks during freshet period. Therefore, it can be said that wind generation could help in avoiding water spills during freshet period, although the volumes are relatively small.
Figure 5.11: Cumulative Incremental Spills with a Pumped-Storage System
5.7 Variations on Intertie Energy Trade

The changes in net energy trade with the U.S. and Alberta were analyzed. Table 5.3 and Figure 5.12 show the annual and monthly differences in net energy market exchange when the pumped-storage system was added. In general, the effect of the pumped-storage system on the annual energy exchange was of no significance for all wind penetration levels and water years studied, as can be seen in Table 5.3. Regarding monthly net energy exchanges, Figure 5.12 shows that the addition of the pumped-storage system resulted in more energy imports (or less energy exports) during the freshet period and more energy exports (or less energy imports) during late summer. The reason for this change was that a portion of the energy in light-load hours was used by the pumped-storage system for storing water in the freshet period for use during high-load hours in summer, when energy price are more attractive than in the freshet period. It is important to emphasize that, as mentioned in Section 5.2, revenues in the BC Hydro system from energy trade did increase due to the energy shift service provided by the pumped-storage system.

With regards to the effect of wind penetration on the net energy exchange, it was increased when more wind power was integrated in the system, which means that more energy was exported, particularly during the winter when wind generation is usually high. In fact, wind energy was delivered when it was most needed and when more favourable market transactions could be made. On the other hand, run-of-river generation had its peak generation during the summer and freshet period when least needed to meet the BC Hydro system load and when market prices were low.

<table>
<thead>
<tr>
<th>Scenarios Studied</th>
<th>Dry Water Year</th>
<th>Normal Water Year</th>
<th>Wet Water Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>10% Wind Penetration No Pump</td>
<td>-2,673</td>
<td>650</td>
<td>1,950</td>
</tr>
<tr>
<td>10% Wind Penetration W/ Pump</td>
<td>-2,662</td>
<td>660</td>
<td>1,897</td>
</tr>
<tr>
<td>20% Wind Penetration No Pump</td>
<td>-1,229</td>
<td>1,715</td>
<td>3,321</td>
</tr>
<tr>
<td>20% Wind Penetration W/ Pump</td>
<td>-1,219</td>
<td>1,730</td>
<td>3,237</td>
</tr>
<tr>
<td>30% Wind Penetration No Pump</td>
<td>-171</td>
<td>2,507</td>
<td>4,348</td>
</tr>
<tr>
<td>30% Wind Penetration W/ Pump</td>
<td>-164</td>
<td>2,519</td>
<td>4,221</td>
</tr>
<tr>
<td>40% Wind Penetration No Pump</td>
<td>1,076</td>
<td>3,511</td>
<td>5,541</td>
</tr>
<tr>
<td>40% Wind Penetration W/ Pump</td>
<td>1,062</td>
<td>3,509</td>
<td>5,370</td>
</tr>
</tbody>
</table>

Table 5.3: Annual Net Energy Exchange for Different Scenarios Studied, in GWh
Figure 5.12: Cumulative Net Energy Market Exchange Comparison

- Dry Water Year (1969). 20% Wind Penetration
  - No Pumped-storage system
  - W/ Pumped-storage system

- Normal Water Year (1968). 20% Wind Penetration
  - No Pumped-storage system
  - W/ Pumped-storage system

- Wet Water Year (1969). 20% Wind Penetration
  - No Pumped-storage system
  - W/ Pumped-storage system
5.8 Financial Feasibility Analysis

A financial feasibility analysis was prepared according to the guidelines proposed in Section 3.5. Table 5.4 summarizes the results of this analysis. The annual benefits of the project were presented in Table 5.2 and they were prorated according to a typical distribution of normal, dry and wet water years in BC. Therefore, the annual benefit used in this analysis corresponded to the average of five (5) normal water years, three (3) wet water years and two (2) dry water years. Table 5.4 indicates that the pumped-storage system project showed a positive Net Present Value (NPV) for the four wind penetration scenarios analyzed. The projects Internal Rate of Return (IRR) were on average 8.3%, which was in the order of typical IRR for a large-scale hydro projects. The payback period of 14-15 years could be also attractive considering that the total project lifetime considered in this analysis was 50 years.

<table>
<thead>
<tr>
<th>Summary Table</th>
<th>Wind 10% Penetration</th>
<th>Wind 20% Penetration</th>
<th>Wind 30% Penetration</th>
<th>Wind 40% Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPV ($US million)</td>
<td>63.4</td>
<td>120.7</td>
<td>172.7</td>
<td>275.7</td>
</tr>
<tr>
<td>IRR (%)</td>
<td>8.3%</td>
<td>8.2%</td>
<td>8.1%</td>
<td>8.5%</td>
</tr>
<tr>
<td>Payback Period (years)</td>
<td>14.9</td>
<td>15.1</td>
<td>15.3</td>
<td>14.5</td>
</tr>
<tr>
<td>Levelized Cost Capacity (US$/kW-yr)</td>
<td>75.1</td>
<td>75.1</td>
<td>75.1</td>
<td>75.1</td>
</tr>
</tbody>
</table>

Table 5.4: Summary of Project Financial Indicators

Levelized costs represent the present value of the total cost of building and operating a generating plant over its financial life, converted to equal annual payments and amortized over expected annual generation from an assumed duty cycle. The levelized cost of energy projects are usually indicated as monetary units per MWh of annual energy generated and they are used to compare between different alternatives. The levelized cost of capacity is not a typical financial indicator for energy projects, but it can be useful to compare among different capacity-oriented power projects. The levelized cost of the pumped-storage system is within the order of magnitude of other capacity-oriented projects considered by BC Hydro in its 2008 LTAP (BC Hydro, 2008C).

A sensitivity analysis was also prepared for the pumped-storage hydro system. In this analysis the following financial variables were modified:

- Discount rate varied from 6% to 8%,
- Capital costs were increased 20% and reduced 20%, and
- Annual benefits were increased 20% and reduced 20%.

Figure 5.13 shows the variation of the project NPV with wind penetration and the discount rate. The project capital costs (capital costs are proportional to the installed pumped-storage capacity) and NPV increased when wind penetration increased. The project NPV increased by approximately 30% for a 6% discount rate, while the NPV decreased by approximately 20% for an 8% discount rate.

Table 5.5 and Figure 5.14 show the variation of the project IRR when the financial variables discussed above were modified. The red line represents the limit level of 6% IRR. Projects below 6% IRR could be considered not financially attractive. It can be seen in this figure that all IRRs were above this 6% limit except in Case C, when capital costs were increased by 20% and when the annual benefits of the project decreased by 20%. For Case B and Case F the IRR was reduced below 8%, which can make the project less competitive with other possible capacity alternatives.
<table>
<thead>
<tr>
<th>Case</th>
<th>Capital Cost Variation (%)</th>
<th>Project Benefits Variation (%)</th>
<th>Wind 10% Penetration</th>
<th>Wind 20% Penetration</th>
<th>Wind 30% Penetration</th>
<th>Wind 40% Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>+20%</td>
<td>+20%</td>
<td>8.3%</td>
<td>8.2%</td>
<td>8.1%</td>
<td>8.5%</td>
</tr>
<tr>
<td>B</td>
<td>+20%</td>
<td>0%</td>
<td>7.0%</td>
<td>6.9%</td>
<td>6.8%</td>
<td>7.2%</td>
</tr>
<tr>
<td>C</td>
<td>+20%</td>
<td>-20%</td>
<td>5.6%</td>
<td>5.5%</td>
<td>5.4%</td>
<td>5.7%</td>
</tr>
<tr>
<td>D</td>
<td>0%</td>
<td>+20%</td>
<td>9.8%</td>
<td>9.7%</td>
<td>9.6%</td>
<td>10.1%</td>
</tr>
<tr>
<td>E</td>
<td>0%</td>
<td>0%</td>
<td>8.3%</td>
<td>8.2%</td>
<td>8.1%</td>
<td>8.5%</td>
</tr>
<tr>
<td>F</td>
<td>0%</td>
<td>-20%</td>
<td>6.7%</td>
<td>6.6%</td>
<td>6.5%</td>
<td>6.9%</td>
</tr>
<tr>
<td>G</td>
<td>-20%</td>
<td>20%</td>
<td>12.0%</td>
<td>11.8%</td>
<td>11.7%</td>
<td>12.3%</td>
</tr>
<tr>
<td>H</td>
<td>-20%</td>
<td>0%</td>
<td>10.2%</td>
<td>10.1%</td>
<td>9.9%</td>
<td>10.4%</td>
</tr>
<tr>
<td>I</td>
<td>-20%</td>
<td>-20%</td>
<td>8.3%</td>
<td>8.2%</td>
<td>8.1%</td>
<td>8.5%</td>
</tr>
</tbody>
</table>

Table 5.5: Variation of the Project IRR for Different Capital Costs and Annual Benefits

Figure 5.14: Variation of the Project IRR for Different Capital Costs, Annual Benefits and Wind Penetration
DISCUSSION AND CONCLUSIONS

This chapter summarizes the most relevant findings of this research and provides discussion on how the results obtained could be interpreted and applied in future development of pumped-storage hydro systems. Finally, recommendations for future research are outlined.

6.1 Summary

The analysis presented in this research showed how stochastic and deterministic linear programming models can be applied to study the integration of different energy portfolios and pumped-storage hydro facilities. The deterministic linear programming model GOM, which is extensively used by BC Hydro operations and planning engineers to assess the feasibility and benefits of many capital and rehabilitation investments projects at BC Hydro, was adapted to assess the impacts of wind integration. The model simulated BC Hydro hourly operations for a one year period in order to optimize the value of BC Hydro resources. A stochastic short-term version of GOM was implemented in this research to simulate the BC Hydro’s short-term planning process, and was used to estimate the scheduling cost or foregone day-ahead market opportunities resulting from integration of wind power in the BC Hydro system. This version of GOM could be used in the future for the analysis of BC Hydro operations as more wind power is integrated in the system and as a second generation of the STOM model developed by Shawwash et al. (2000).

This analysis is in general agreement with the results obtained by Evans (2009), which primarily indicate that integrating wind energy into a hydroelectric system can take advantage of the hydro system greater flexibility to shift the integrated wind energy to the most opportune export time periods. Wind complements other existing clean renewable resources in BC, such as run-of-river hydropower, and the mixed energy portfolio of both resources could potentially be used to optimize the operation of the BC Hydro system.

In the case of the pumped-storage hydro system, the modeling of this facility required the adaptation of the GOM model to a mixed-integer programming version that, although was implemented successfully, required significantly computational effort and time to solve the optimization problem. The pumped-storage hydro system proposed for the Mica generating
station produced additional benefits for the BC Hydro system at reasonably competitive costs. This facility could be incorporated in the existing hydro reservoir systems in BC in order to provide ancillary services that can be used to manage the variability of wind power in BC and in neighbouring regions, and to also provide shift energy benefits in energy trade with other utilities.

6.2 Conclusions

The following conclusions can be made about the results of this research:

a) The modifications included in the GOM model to simulate a pumped-storage hydro system indicated that this model can incorporate the mixed-integer constraints and variables required for the operation of this system but these constraints led to significant increase in the model solution times. This longer solution times created difficulty in the simulation process and studies, particularly when these modifications were incorporated in the stochastic version of GOM. In effect, the short-term simulation of one year of BC Hydro operations required solutions times over five days with an exhausting follow-up process to ensure that the runs results obtained were of reasonable quality for this analysis. Therefore, it is recommended that the use of the mixed-integer version of GOM should be avoided if possible and be limited to modeling applications with a limited number of variables and constraints. It is also recommended that a solution algorithm be developed to decompose and solve this stochastic mixed-integer programming problem.

b) The adaptation of the GOM model into a short-term version with stochastic linear programming with recourse proved successful. The GOM model could then be further adapted to include other stochastic parameters such as market prices and inflows. However, the inclusion of additional stochastic scenarios could also lead to a significant increase in the model solution time. The solution time for each run used to simulate the short-term operation of the BC Hydro system (for four operation days) without the pumped-storage facility was approximately eight (8) minutes with 48 stochastic scenarios. In addition, the solution time increased geometrically when the number of stochastic scenarios was also increased. Decomposition and simplification techniques could be incorporated to improve the model current formulation and solution times.
c) The addition of a pumped-storage hydro system to the BC Hydro system could provide additional economic benefits which tend to increase when more wind power is integrated. Moreover, this pumped-storage system could provide different services for the BC Hydro system. First, it could provide energy shift to maximize the economic benefit of energy transactions with other utilities in the Pacific Northwest, particularly during the freshet period. Second, the pumped-storage system could provide down regulation (if equipped with AGC capability) and following down reserves that could be used to facilitate wind integration within BC. Finally, the additional flexibility provided by the pumped-storage system could be used to provide ancillary services to other utilities and to wind generators in the Pacific Northwest.

d) The wind integration costs obtained in this study were in the order of magnitude of other integration costs estimated for different electric utilities (see Section 2.1 and Holtinnen, 2008). However, the results obtained in this research surprisingly showed opposite trends. The cost of incremental wind reserves tend to increase when wind penetration increased while scheduling costs decreased when wind penetration increased. Such results should be considered with caution and they only served the purpose of estimating the magnitude of the cost reduction provided by the pumped-storage hydro system. Nevertheless, the effect of the load forecast error in reducing the scheduling cost was found to be considerable. Therefore, it is recommended that the wind and the load forecast error be considered to estimate the impact of wind integration in the day-ahead time horizon.

e) The pumped-storage system analyzed in this study did show reduced wind integration costs that are attributable to the incremental wind reserves and foregone day-ahead market opportunities by approximately US$ 0.75 per MWh of wind generated. This reduction of wind integration costs could be an incentive to integrate more wind power projects in BC. The combined IPP energy output consisting of wind and run-of-river was more uniform throughout the year, which could help in the operation and optimization of the BC Hydro resources.

f) The analysis showed that the incorporation of the pumped-storage hydro system in BC Hydro system can result in an increment in the water stored in the reservoir upstream of the pumped-storage hydro system, particularly during freshet period. Water spills were also
reduced during this season, but then they were increased in late summer, which could be resulting from the end storage limits used in this research. A multi-year modeling approach could influence these operation patterns and perhaps lead to a better water spill reduction and a more optimal reservoir storage pattern.

g) The financial feasibility analysis prepared in this study indicated that the pumped-storage system could be a financially attractive alternative to optimize the operation of the BC Hydro system and to provide greater flexibility for the integration of wind power. However, this analysis also indicated that this result can be sensitive to changes in the estimated capital cost of this project and to the estimated annual revenues produced by this project.

6.3 Future Work

The modeling approach proposed in this research could be further extended to model different wind development scenarios in BC, IPP energy portfolios, water years, market depths, intertie capacity scenarios, market prices and extended to include other stochastic parameters, etc. These arrangements could be easily made in the existing model structure, because only parameters and limits (i.e. constraints) need to be redefined in the model. However, other aspects of this research could be extended and will require much more work effort. These aspects are outlined in the following paragraphs.

Regarding the short-term modeling to estimate scheduling costs, price discount factors were used to estimate the effect of wind power in day-ahead and real-time market prices. However, these price discount factors were only prepared in consultation with power trading experts and they will require a comprehensive technical analysis if this analysis is to be extended. In the case of day-ahead discount factors, an analysis could be prepared by analysis of neighbouring electric markets such as Alberta, Mid-C and California to estimate the impacts of day-ahead wind power forecasts and spot prices. This could be done by analysis of the days when wind generation was low and days when wind generation was high to investigate if a relationship exists between these two parameters. According to the literature (see Jónsson et al., 2009), this relationship exists but could be highly non-linear and time dependent. In the case of real-time price factors, power traders agree that wind power is one the most important factors affecting these prices in the Pacific Northwest. Therefore, a relationship could be researched to estimate the degree of
correlation between wind in different geographic areas in the Pacific Northwest and real-time market prices. New market opportunities could be found and exploited in real-time when the excess of energy produced in a wind region could be used to compensate for the shortage of energy in another wind region. It is then recommended to investigate and develop the potential relationships between real-time market prices in the Mid-C market, wind generation within BC and other areas in the Northwest, such as BPA.

The shape of water spills and reservoir storage for Mica obtained in this research suggest that a better utilization of the hydro resources and a more complete assessment of the capabilities and values of available reservoir storage flexibility could be obtained if a multi-year optimization including wind generation is modeled. In this way the surplus of stored water could be carried over further into the fall and winter months, or even longer in dry years, before the reservoir levels must be reduced to make room for spring snowmelt and runoff. Likewise, surplus energy from wet years could be used to keep reservoir levels higher so that more energy would be available during later years that may be drier, with less available hydroelectric energy.

Finally, the results of this research made it clear that pumped-storage hydro provides benefits to the BC Hydro system. These benefits could be even more significant if the modeling of the electrical transmission system is incorporated. Most transmission systems, including the BC Hydro system, have many bottlenecks that constraints the flux and transfer of electricity from one region to the next. As wind power resources far from load centers are developed, they could end up competing with other energy resources for transmission capacity, and limit the operational flexibility of the rest of the generation system. In this way pumped-storage hydro could provide an additional benefit storing the wind generation to avoid network congestion and competition with other resources, thus avoiding transmission bottlenecks. This could be very significant in the Peace Region for example, where most of the wind power projects in BC will be developed and large hydropower projects such as Site C are being proposed. The addition of a pumped-storage system in this region could be an attractive alternative to complement the optimum development of renewable resources in BC.
REFERENCES


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