Assessing the Impacts of Wind Integration in the Western Provinces

by

Amy Sopinka
B.A., Queen's University, 1992
M.A., McGill University, 1995

A Dissertation Submitted in Partial Fulfillment
of the Requirements for the Degree of

DOCTOR OF PHILOSOPHY

in the Department of Geography

Supervisory Committee

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Abstract

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Increasing carbon dioxide levels and the fear of irreversible climate change has prompted policy makers to implement renewable portfolio standards. These renewable portfolio standards are meant to encourage the adoption of renewable energy technologies thereby reducing carbon emissions associated with fossil fuel-fired electricity generation. The ability to efficiently adopt and utilize high levels of renewable energy technology, such as wind power, depends upon the composition of the extant generation within the grid. Western Canadian electric grids are poised to integrate high levels of wind and although Alberta has sufficient and, at times, an excess supply of electricity, it does not have the inherent generator flexibility required to mirror the variability of its wind generation. British Columbia, with its large reservoir storage capacities and rapid ramping hydroelectric generation could easily provide the firming services required by Alberta; however, the two grids are connected only by a small, constrained intertie.

We use a simulation model to assess the economic impacts of high wind penetrations in the Alberta grid under various balancing protocols. We find that adding

wind capacity to the system impacts grid reliability, increasing the frequency of system imbalances and unscheduled intertie flow.

In order for British Columbia to be viable firming resource, it must have sufficient generation capability to meet and exceed the province's electricity self-sufficiency requirements. We use a linear programming model to evaluate the province's ability to meet domestic load under various water and trade conditions. We then examine the effects of drought and wind penetration on the interconnected Alberta – British Columbia system given differing interconnection sizes.

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Dedication

To my parents, Nick and Suzanne Sopinka, for their unwavering support and optimism.

To my siblings, Zoe, Heidi and Steve, who I know, without question, are always in my corner.

To my husband, Geoff – he knows what he did.

Finally, to my children who one day will understand why I've been so busy.

Glossary

Alberta Electric System Operator (AESO): The Alberta system operator and balancing authority responsible for managing the province's electricity market.

Ancillary services: Additional services required to support the generation, transmission and distribution of electricity. These include operating reserves, load shed schemes, transmission must run (TMR) services and black start capabilities.

Alberta Integrated Electric System (AIES): The generation, transmission and distribution network in Alberta.

Balancing Pool: A not-for-profit corporation set up to redistribute the proceeds of the Alberta PPA auction and to manage the provincial generating assets remained unsold after the initial auction in 2000.

Baseload: The lowest average system load.

Baseload generator: A generating unit that is designed to operate at full capability

Behind-the-fence (BTF) generation: On-site generation that serves its own load.

Black start: An ancillary services consisting of generating units that are capable of being started without an outside electrical supply

Capacity: The maximum amount of power that can be produced by a generator under ideal conditions. This is also known as the nameplate rating.

Capacity factor: The ratio of average generation to the capacity rating of an electric generating unit for a specific period (expressed in per cent).

Contingency reserves: One of the ancillary services consisting of part-loaded generating units, intertie flow or load that can ramp up or down to provide supply flexibility.

Economic dispatch: A standard means of dispatching generators to meet demand by directing the generators from least cost to most expensive. This protocol insures that demand is satisfied at the lowest cost.

Energy: How much power is consumed or produced over some period of time. This is described in kilowatt-hours, megawatt-hours or gigawatt-hours.

Energy market merit order (EMMO): Also known as the supply stack. It is comprised of generator offers and source bids sorted in order according to price.

Firming: Creating an uninterruptible supply from an intermittent energy source using back up resources.

Forced outage rates: The percentage of time a conventional generating unit is unavailable due to unforeseen circumstances.

Gigawatt (GW): Equal to one thousand MW

Gigawatt-hour (GWh): Equal to one thousand MWh

Hour ending (HE): The hour ending format used to designate specific times in electricity transactions. The hour ending format takes a value between 1 and 24. For example, hour ending 10 refers to the time between 9:01 a.m. and 10:00 a.m.

Load following services: An ancillary service provided by generators to manage fluctuations in load. These services are used for balancing the system over a longer term than regulating reserves and over a shorter time than contingency reserve provision.

Load shed services (LSS): A means of increasing capacity on the intertie by paying large loads to be disconnected to the grid when the frequency on the intertie drops below a certain value.

Kilovolt (kV): A unit of electrical voltage in transmission lines. One kilovolt equals 1,000 volts. Voltage is the force that causes a current to flow along a circuit. Higher voltage transmission wires can more transmit electricity over longer distances than lower voltage lines.

Kilowatt (kW): An instantaneous measure of power that is equal to 1000 watts

Kilowatt-hour (kWh): A measure of electricity flow equal to one thousand watt-hours. The average household in Canada uses about 12,000 kWh per year.

Megawatt (MW): An instantaneous measure of power that is equal to 1000 kilowatts, or one million watts.

Megawatt hour (MWh): A measure of the flow (or consumption) of electricity, an average household uses about 12 MWh per year.

Mid-Columbia Hub (Mid-C): The area along in the Columbia River in the U.S with five non-federal hydroelectric stations. It is one of the most active electricity trading points in the WECC region.

Must-offer must-comply (MOMC): A rule in electricity markets wherein generators are required to state an offered volume amount prior to the operational hour and deliver that amount of energy to the grid during that hour.

North American Electricity Reliability Council (NERC): The U.S. federal agency responsible for creating and enforcing electricity reliability standards.

Open cycle gas turbine (OCGT): a fast ramping natural-gas fired generator.

Operating reserves: One of the ancillary services; operating reserves consist of both regulating and contingency reserves.

Over dispatch: One of the protocols available for system balancing. The system operator continues to dispatch generators as required in order to meet the system ramp rate. Because they are used to meet ramp rate requirements and not used for energy provision, over dispatched generators will only be dispatched on (or off) for very short periods.

Path rating: The capacity of a transmission line under ideal conditions; it is related to the voltage of the transmission line.

Peak load: The maximum instantaneous load.

Peaking unit: A fast ramping unit that is called on sporadically to provide electricity to the grid to meet peak load.

Pool price: The average of the sixty system marginal prices produced over a one hour period.

Power: the amount of electricity produced instantaneously by system resources.

Power purchase agreement (PPA): A contract between an electricity producer and buyer. Amongst other things, the PPA sets out the purchase volume, price and any other obligations that are integral to the arrangement.

Regulating reserves: A portion of spinning reserves under automatic generator control; these resources are responsible for balancing demand in the second by second time frame.

Renewable portfolio standard (RPS): a requirement for load serving entities to meet a certain portion of their load with electricity generated by acceptable renewable energy technologies.

Synchronous: Operating at the same frequency of the grid. In North America this is 60 Hz per second.

System marginal price (SMP): The offer (or bid) price associated with the last block of energy required to meet load in any one minute period.

Terawatt (TW): One thousand gigawatts

Terawatt-hour (TWh): One thousand gigawatt-hours (GWh)

Transmission Must Run (TMR): An ancillary service also known as reliability must run. Generators that are dispatched out of merit order required to operate because congestion in the transmission system prevents electricity from moving from generators to load.

Watt: a measure of electrical energy.

Watt-hour: One watt of power supplied to, or consumed by, an electric circuit for one hour.

Western Electricity Coordinating Council (WECC): Also known as the Pacific Intertie. A synchronous electricity grid comprised of all or portions of 14 western states plus Alberta, British Columbia and the Baja California region of Mexico.

Chapter 1: The Growth in Wind Capacity

1.0 Introduction

Catastrophic predictions of increasing global temperatures have catapulted the issue of climate change to the forefront of environmental concerns. The theory of climate change suggests that the production of greenhouse gases (GHG) leads to higher atmospheric concentrations of the gases that lead to greater surface temperatures. Land use changes, changes in agricultural practices, deforestation and desertification have large-scale impacts on climate (Karl & Trenberth, 2003). These effects, in combination with anthropogenic emissions, mean that the production of carbon dioxide (CO_2) significantly exceeds terrestrial absorption rates.

> For the recent period 2000 - 2005, the fraction of total anthropogenic CO_2 emissions remaining in the atmosphere (the airborne fraction) was 0.48. This fraction has increased slowly with time implying a slight weakening of sinks relative to emissions (Raupach et al., 2007, p. 10292).

Globally, CO_2 emissions are increasing. Raupach et al.(2007) find that the "mean global atmospheric CO_2 concentration has increased from 280 ppm in the 1700s to 380 ppm in 2005 at a progressively faster rate each decade" (p. 10288). Global CO_2 emissions, plotted in Figure 1.1, exhibit an increasing trend that is particularly evident in the last ten years of data (World Bank, 2011).

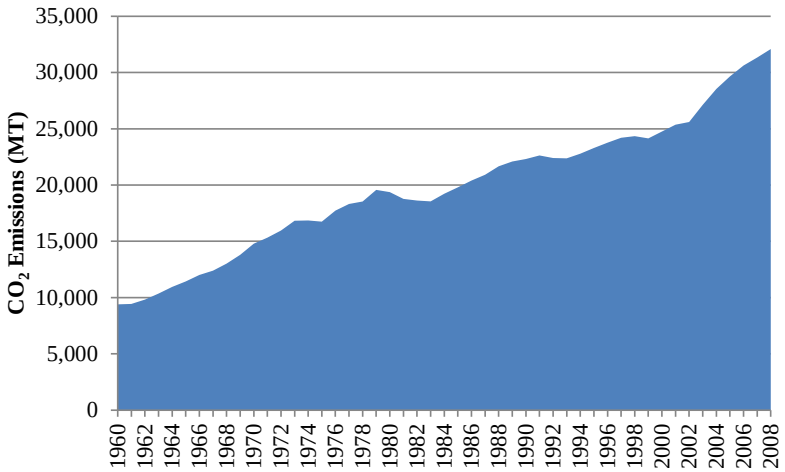

Figure 1.1: Growth in global CO_2 emissions

The combustion of fossil fuel greatly adds to CO_2 emissions. Malla (2009) states, "since 1750, it is estimated that about two-thirds of anthropogenic CO_2 emissions – the most important anthropogenic GHG – have come from fossil fuel burning and in recent years these emissions have continued to increase" (p. 1). Electricity generation uses vast quantities of fossil fuels as its primary energy source and is therefore one of the major producers of CO_2. World CO_2 emissions and electricity production, graphed in Figure 1.2, have a correlation coefficient of 0.78 (World Bank, 2011).

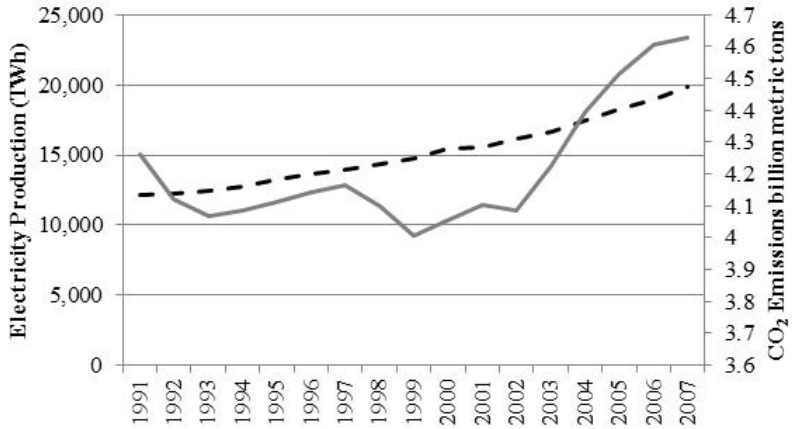

Figure 1.2 Global CO2 emissions and electricity production

The share of power generation in global energy-related CO_2 emissions has increased from 36 percent (8.8 Gt CO_2) in 1990 to 41 percent (11.0 Gt CO_2) in 2005 (Malla, 2009, p. 1). In the U.S. in 2007, the electric generating sector produced over 40 percent of total domestic CO_2 emissions, increasing steadily from 32 percent in 1980. The Energy Information Administration (EIA) states that two-thirds of U.S. electricity generation is fossil fuel based (EIA, 2007). There are, however, differences in the electricity sector's fossil fuel intensities across countries. Malla (2009) provides data on the share of fossil fuel-fired generation in a variety of countries. In aggregate, Canada's electricity sector is only 24 percent fossil fuel based, whereas Australia and China respectively produce 93 percent and 82 percent of their electricity from fossil fuels. Countries with a greater share of fossil fuel generated electricity will also have a higher share of energy-related CO_2 emissions.

Electricity sector emissions are not expected to decline as electricity demand is forecast to increase, despite the global recession. EIA (2009) predicts world net electricity generation to increase by an average of 2.4 percent per year from 2006 to

2030. Consequently, world energy-related CO_2 emissions are expected to grow from 29.0 billion metric tons in 2006 to 33.1 billion metric tons in 2015 and 40.4 billion metric tons in 2030.

1.1 Renewable Energy Standards

In response to the climate change threat, governments across the globe have begun to address the electricity sector's role in producing CO_2. In Europe, the U.S. and Canada, recent climate change policy has included a mandatory renewable energy component. The European Union goal is to achieve CO_2 emissions reductions of 20 percent below 1990 levels by 2020.

Renewable portfolio standards (RPS) are legislated on a state-by-state basis in the United States; they require retail electricity suppliers to acquire a certain minimum quantity of electricity from eligible renewable energy resources. Twenty-nine states plus the District of Columbia and Puerto Rico have enacted a RPS. The state requirements vary widely. In California, the RPS program requires electric corporations to increase procurement from eligible renewable energy resources by at least one percent of their retail sales annually, until they reach 33 percent by 2020 (CPUC, 2009a). In New York State, the goal is to have 29 percent of retail electricity provided by renewable sources by 2015; Washington State has an RPS of 15 percent by 2020. A complete description of RPS across the U.S. is provided by the U.S. Department of Energy (2011).

In Canada, electricity generation is a provincial responsibility. The Province of British Columbia requires that clean or renewable electricity generation will provide 93 percent of total generation (Province of British Columbia, 2012). The fuel mix of

Alberta's electricity generation portfolio is determined exclusively by private investment and, as such, there is no minimum procurement standard for renewable energy.

1.2 Growth in Wind Capacity

Policies to increase clean energy procurement are aimed at encouraging the adoption of emissions-free energy sources largely as a means of mitigating CO_2 emissions. There are a variety of renewable energy technologies that meet this criterion, including geothermal, biomass, hydrokinetic (wave, tidal and run-of-river hydro), wind, and solar energy (IEA, 2004). While the total renewable energy supply grew by 2.3 percent per year over the last 33 years, geothermal, solar and wind energy technologies recorded an annual growth of nearly 8.2 percent (IEA, 2006).

Worldwide

Of all of the renewable energy technologies, the greatest growth has been in the number of installed wind turbines; the worldwide installation of wind power facilities (WPF) has yielded 197,039 MW of wind capacity at the end of 2010.[1] The Global Wind Energy Council (GWEC, 2010) estimates growth in installed wind capacity across various regions; these values are charted in Figure 1.3. `

[1] A 1 MW wind power facility can produce approximately 2 GWh of electricity over the course of a year, while the average Canadian residential household will consume approximately 12 MWh of electricity per year. Thus, one mid-size wind turbine could potentially supply electricity to nearly 170 homes.

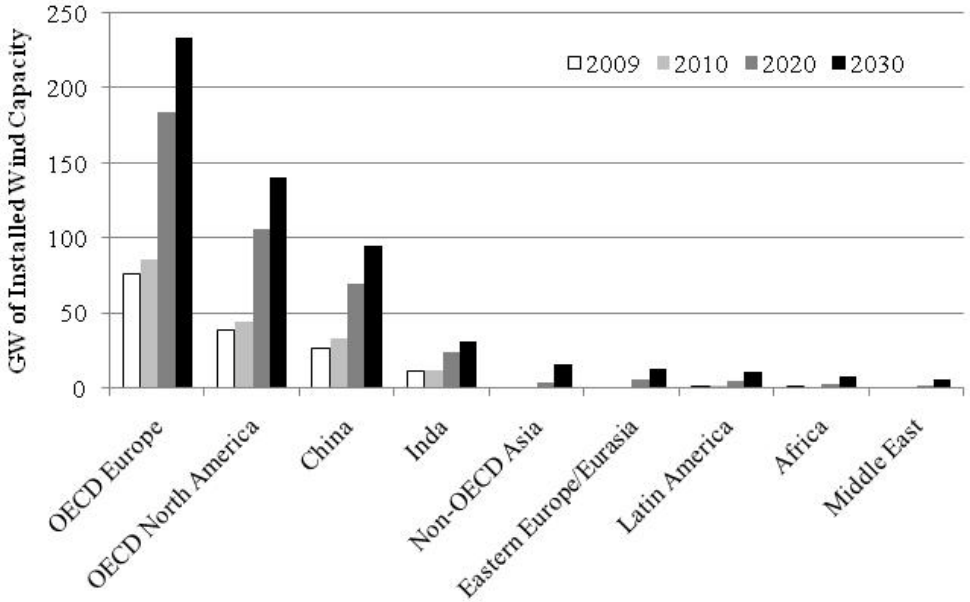

Figure 1.3: Actual and forecast growth in global wind capacity 2009 - 2030

European nations will drive the global adoption of wind technology. By 2030, GWEC (2010) forecasts 234 GW of wind capacity in OECD Europe alone despite the fact that the global recession has impacted European renewable energy growth. Between 2009 and 2010 there was a 10 percent decrease in the European Union's incremental installed wind energy capacity; onshore wind energy fell by 13 percent while the offshore market grew by 9.5 percent during the same period. In 2010, Spain accounted for the greatest amount of wind capacity additions in Europe. Table 1.1 is populated with data from GWEC (2010) that enumerate the amount of wind capacity installed in selected EU countries in 2010.

Table 1.1: EU Wind Installation 2010

Country Name	2010 Wind Installation (MW)
Spain	1,516
Germany	1,493
France	1,086
UK	962
Italy	948
Sweden	603
Romania	448
Poland	382
Belgium	350
Portugal	345

United States

In the United States, installed wind capacity grew from 2,248 MW in 1999 to over 39,135 MW in 2010 as shown in Figure 1.4 (EIA, 2011).

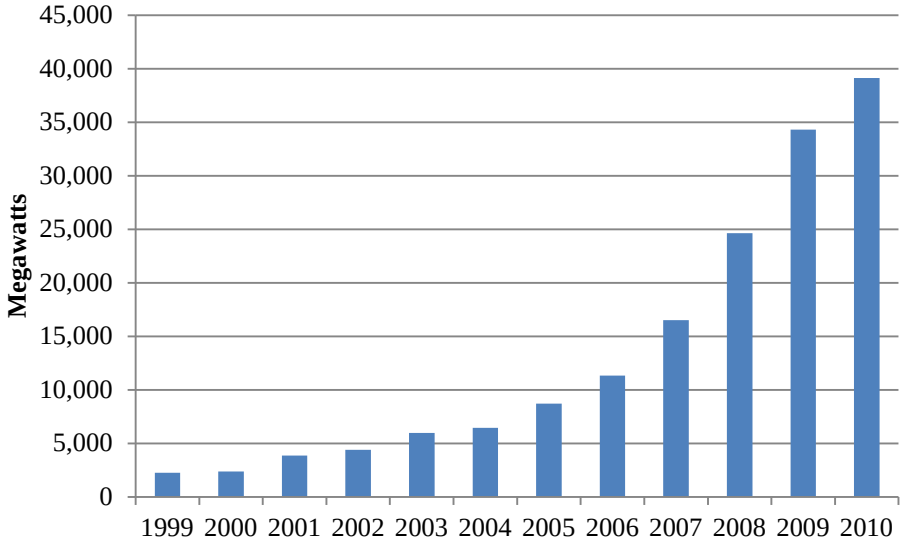

Figure 1.4: Installed wind capacity in the United States, 1999-2010

Canada

The growth of Canada's installed wind capacity rose from 137 MW in 2001 to

4,611 MW in 2011. Cumulative wind capacity figures from Canadian Wind Energy Association (CanWEA, 2011) are plotted in Figure 1.5.

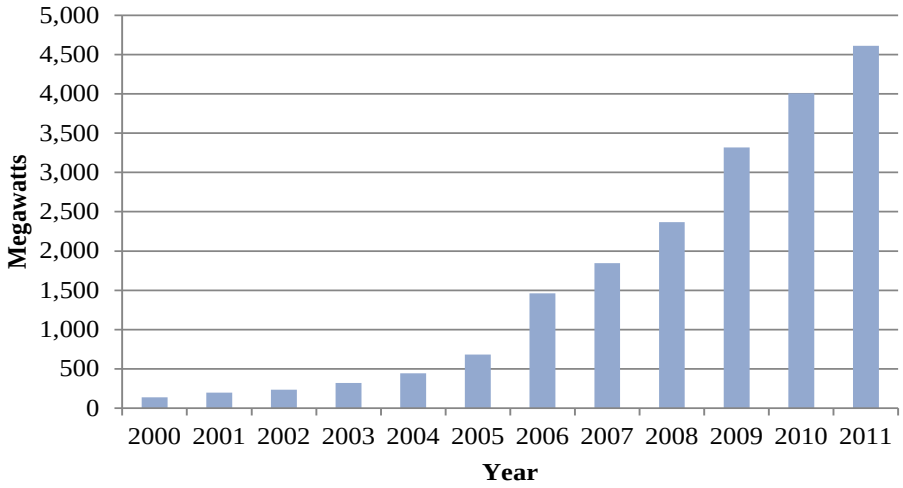

Figure 1.5: Total installed wind capacity in Canada

Canada's installed wind energy is not distributed equally across the country. Table 1.2 details the amount of available wind energy capacity in each of the provinces as well as the Yukon Territory (CanWEA, 2011).

Table 1.2: Canada's Installed Wind Capacity as of March 2012

Location	Installed Wind Energy Capacity (MW)
Newfoundland	55
Prince Edward Island	164
Nova Scotia	286
New Brunswick	294
Quebec	1,057
Ontario	1,970
Manitoba	242
Saskatchewan	198
Alberta	891
British Columbia	248
Yukon	1

Western Canada

Alberta's electric industry experienced strong growth in installed wind capacity since the deregulation of the market in 2001.[2] The Alberta Electric System Operator (AESO) is anticipating over 1,575 MW of available wind capacity by the end of 2012 and possibly 4,000 MW of wind capacity by 2020. Alberta's annual additions and cumulative installed capacity between 2001 and 2020 are shown in Figure 1.6 (AESO, 2010f). All but one of the existing wind projects is located in the southern part of the province, providing a high degree of geographic concentration and output correlation (see Figure 1.7).

[2] Deregulation allows investors to participate in the hourly energy market through the construction and operation of privately owned generating facilities (see Chapter 2). Given that the relatively low capital costs associated with wind turbine technology are approximately $2.3 million per MW (CanWEA, 2008) and the price taking behaviour of the wind generators, it is not surprising that wind capacity in Alberta has increased; this, despite the fact that the provincial government has not imposed a renewable energy standard.

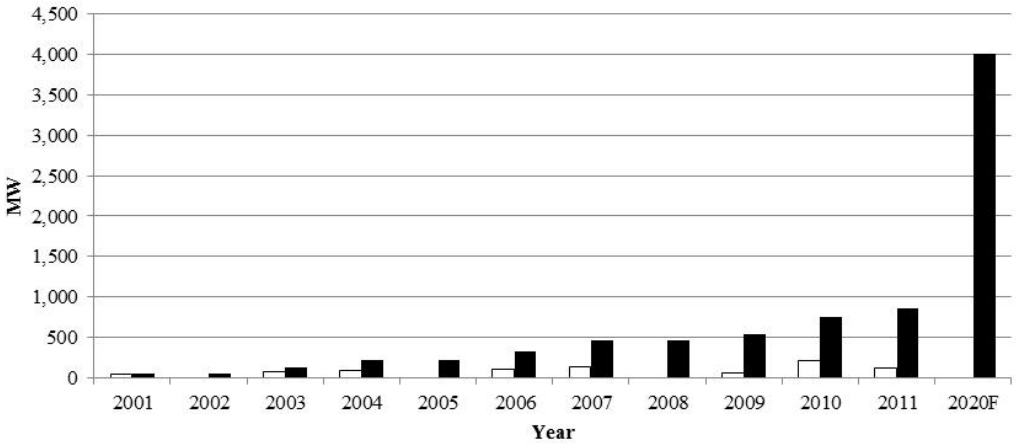

Figure 1.6: Alberta annual additions and cumulative installed wind capacity

By contrast, British Columbia has only a fraction of Alberta's installed wind capacity. The first wind power facilities at Bear Mountain came online in 2009 with 102 MW of capacity. A single 1.5 MW turbine was placed at Grouse Mountain, ostensibly to showcase BC at the forefront of renewable energy policy during the 2010 Olympic Games held in Vancouver. The Dokie wind project came online at the beginning of 2011 with 144 MW of installed capacity. Both the Dokie and Bear Mountain projects are located in the Peace region in northeast British Columbia, east of the Rocky Mountains.

There are a variety of reasons why British Columbia has lagged in the adoption of wind energy technology. The main cause can be attributed to the structure of the electricity markets in the province. Alberta has a fully deregulated wholesale market. The generation mix is investor-driven. The BC electricity sector is characterized as a near monopoly on the selling side and a monopsony with respect to electricity purchases – this structure is suited to large capital-intensive projects.

Historically, electric utilities were government–owned entities or regulated

investor-owned firms that were vertically integrated; utilities provided customers with bundled generation, transmission and distribution services. The justification for this economic structure was predicated on high costs of capital for large-scale generation technologies and the inefficiencies associated with multiple competing transmission and distribution systems. However, as newer generation technologies developed, capital and operating costs fell and the size of electric generating units decreased. New gas-fired generating units became efficient and economic at much smaller capacities. The lower cost/smaller scale environment led industrial consumers to advocate for competition on the basis that it would yield lower electricity prices while independent power producers demanded the right to compete.

Wholesale electricity competition required the disbanding of vertically integrated utilities. Transmission assets had to be decoupled from generation assets allowing other power producers to transmit their electricity to end-users. Regulated or publicly owned generation assets needed to be dispersed to reduce market power. Wholesale electricity competition was unrolled in Norway, Denmark, Britain, Alberta, Ontario, Texas and much of the east coast of the United States; and there was the infamous California deregulation exercise (see Navarro and Shames, 2003; Bushnell, 2004).

The key impetus driving deregulation appears to be centered on public reaction around government ownership and provision of electricity. In Alberta, the ownership of the province's generating assets was in the hands of two privately-owned but regulated utilities (TransAlta and ATCO Power) and two municipally-owned utilities – EPCOR (formerly Edmonton Power) and the City of Medicine Hat. Deregulation in Alberta's electricity market was fairly straightforward (see Chapter 2). The transmission system

was mainly, but not exclusively, owned and operated by TransAlta while the province's generating assets were already spread (albeit unequally) across four separate entities. Alberta's frontier mentality yields a low tolerance for government intervention and this is seen in many areas in the province including telecommunications, retail liquor provision and charter school funding.

British Columbia's electricity system is dominated by BC Hydro, a large publicly owned utility that is responsible for 86 percent of the province's generation assets and the entire transmission and distribution systems. BC Hydro constructed and continues to operate the large-scale hydroelectric units built between its inception in 1945, as the BC Power Commission, and its last major project, the Revelstoke dam in 1984. In 1995, as technological changes were leading many jurisdictions towards deregulation, the British Columbia Utilities Commission (BCUC) commenced an electricity market review that culminated in the recommendation that the "government move forward with market reforms that would ultimately break up BC Hydro" (Jaccard, 2001, p. 61). At the same time, the provincial government requested proposals for independent power projects (IPPs). Since the market review, however, the only steps that BC Hydro has taken with respect to deregulation was to separate the utility's transmission functions from it generation assets. This was required by the U.S. Federal Energy Regulatory Commission (FERC) if Powerex, BC Hydro's power marketing subsidiary, was to receive an export permit allowing it to sell electricity in U.S. markets.[3] Meanwhile, BC Hydro continues to advocate for large-scale publicly funded projects by promoting the construction and

[3] In the BC Clean Energy Act, created on June 10, 2010, the provincial government re-integrated the British Columbia Transmission Corporation with BC Hydro

operation of another mega hydroelectric project – the 1,098 MW, $7.9 billion Site C facility.

BC Hydro is an interesting case study especially when juxtaposed against Alberta's electric grid operation. Since deregulation in 2001, Alberta has operated an hourly wholesale electricity market. Decisions about investment in generation assets and technologies are left solely to the discretion of the private sector. In British Columbia, independent power producers face a single buyer and are required to enter into a long-term contract for energy provision. The process for bringing a project online can be extensive and long-term contracts reduce the potential upside to investors. The attrition rate on independent power projects is nearly 30 percent which has limited the penetration of wind power facilities (and other IPP developments) in BC.

Despite the range of economic structures in wholesale electricity markets, in most regions the planning and construction of transmission infrastructure remains in the hands of the public. Across North America the public and private sectors have invested heavily in independent power production technologies, particularly wind power facilities and these generation assets are located far from load centres. New transmission buildouts are required to connect electricity generators to the grid. However, the lead time for transmission projects is much longer than that of generating assets, the construction of transmission lines is expensive, cost allocations are contentious and projects are difficult to site (Bloom, Forrester & Klugman, 2010). As a result, transmission construction lags behind the building of generating assets. For example, in Alberta over 20,000 MW of wind generation projects are on the interconnection queue awaiting assessment and there are significant transmission bottlenecks within the province.

In the U.S., the Federal Energy Regulatory Committee (FERC) used Order 888 to instigate open access transmission tariffs and encourage the creation of regional transmission operators. When that was not successful, the FERC issued Order 1000, a policy that requires public transmission providers in adjacent transmission planning areas to work together with the goal of finding transmission plans that are more cost-effective and efficient. As yet, there is no similar policy in Canada. Provinces construct transmission facilities based on their own internal needs but interprovincial transmission policy would need to come at the federal level and would likely require direction from the National Energy Board.

Insufficient transmission interconnection impacts grid reliability, renewable penetration and is economically inefficient. However, coordination of transmission policy amongst provinces is difficult at best. Pineau (2012) advocates for a national grid integration strategy, stating that a “strong integration movement is leading electricity markets towards a more uniform organization that allows for greater trading and efficiency gains” (p. 23). Adopting a national platform will improve reliability, increase electricity load factors, decrease costs and improve supply security. Pooling resources could provide all provinces with access to low cost hydroelectric generation, while aggregating loads across provinces would increase the baseload of the system and decrease the flexibility required to meet peak load conditions. In increasing access, system costs may be reduced thereby improving the position of the electric consumer.

Environmentally, greater grid integration could allow for more wind generation, as geographic dispersion tends to smooth output (Gross et al., 2008). Green and Vasilakos (2011) show that, while Denmark produced nearly a fifth of its electricity in

2009 using wind power, it was only able to manage this level of wind production due to its strong interconnections with adjacent markets. CEPOS (2009) determines that,

> although Denmark has no electricity storage within its electricity system, it has, for many years and for reasons having nothing to do with balancing wind power, been strongly inter-connected with its neighbours, Germany, Norway and Sweden. These have much larger power systems. To the north, the largely hydroelectric systems of Norway (99% hydro) and Sweden (40% hydro) are able to balance the stochastic variations in Denmark's wind power by continuously turning their hydropower systems up and down. When "excess" wind power electricity flows along the inter-connector into Norway (for example), hydropower can be rapidly turned down to match, effectively "storing" Danish wind power in Norway. As the wind energy falls or ceases, the "stored" electricity can be released very efficiently to make up any shortfall in West Denmark (CEPOS, 2009, p.11).[4]

Piwko et al. (2012) examine the wind integration experiences in Europe, China and North America. They note that due to the geographic dispersion of wind power facilities and the distance of these facilities from the load centres, there are benefits to "creating large balancing areas with few internal transmission grid bottlenecks in power system with relatively large penetrations of wind power" (Piwko et al. 2012, p. 47). However, the transmission buildouts required to support higher wind penetration levels have not occurred. For example, the California Public Utilities Commission (CPUC, 2009) report on California's renewable goal states that, just to meet the 20 percent standard, four major new transmission lines are needed at a cost of $4 billion.

The small balancing areas in North America combined with the history of building large, inflexible baseload plants, means that from a systems operations

[4] Exporting wind power to adjacent regions and importing electricity during periods when wind is not available is costly to Danish consumers. Bach (2009) notes, "wind power significantly increases spot price volatility, with very high prices observed at times of low wind (when conventional generators are required to take up the slack), and very low or even negative prices at times of high wind" (p. 2). This results in Danish electricity being the most expensive in the EU (CEPOS, 2009).

perspective, “even a small amount of wind generation in such a system is very challenging and inevitably leads to excessive curtailment (spilling) of wind energy” (Piwko et al., 2012, p. 51).

Pineau (2012) enumerates three reasons why provinces may not favour grid integration. These include the structure of political incentives both federally and provincially, the reallocation of profits and losses across jurisdictions, and difficulty in recognizing the environmental benefits that would result from greater grid integration. This is true even at a smaller scale when examining the interconnected electric grids of Alberta and British Columbia.

Alberta’s electricity sector is deregulated, thermally dependent, and hampered by its lack of output flexibility. This structure is combined with a substantial and growing segment of wind capacity geographically concentrated in the southwest. To the west, British Columbia’s electric system is predominantly hydroelectric, inherently flexible but has relatively little installed wind capacity. The location of western Canadian generating units is shown in Fig. 1.7.[5]

[5] Figure 1.7 from Canadian Electricity Association (CEA, 2012).

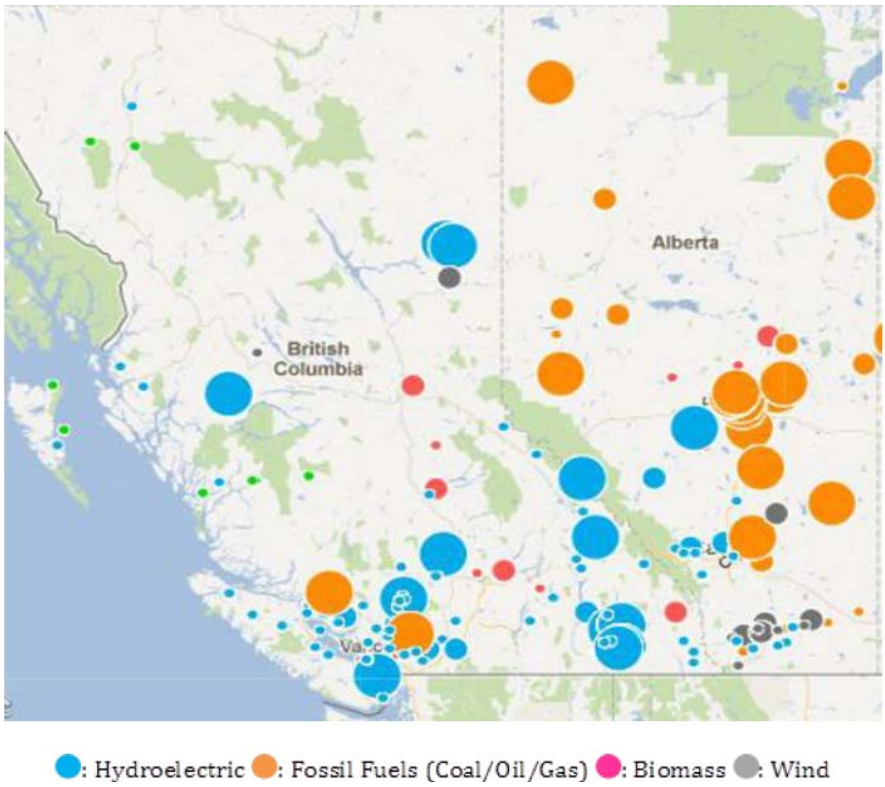

Figure 1.7: Location of generators in Alberta and British Columbia.

Interprovincial electricity trade occurs but is constrained by a small intertie, known as Path 1.[6] Fig. 1.8 shows the BC and Alberta transmission systems.[7] Path 1 consists of a 500kV transmission line between Cranbrook, BC and Langdon, AB and two 138 kV lines between Natal–Coleman, and Teck-Pocaterra. The path rating is 1,000 MW from east to west and 1,200 MW west to east, although the available transfer capacity is

[6] The lack of adequate transmission capacity between the two westernmost provinces, Alberta and British Columbia, was apparent on July 9, 2012. Alberta faced a heat wave and six of its generators tripped offline. As a result of the high demand and low supply, the Alberta Electric System Operator issued orders for firm load shed (i.e., rolling brown outs) until its system could be restored. At the same time, BC Hydro was spilling water over its dams (and not generating electricity) because of high water conditions. Although some electricity was transmitted from BC to Alberta during this crisis, the existing available transfer capacity between the provinces did not allow for enough of BC's electricity to be sent to Alberta to completely mitigate the supply shortage issue.

[7] From the WECC 2002 Load and Resources Subcommittee Annual Report

often significantly less (see Chapter 2).

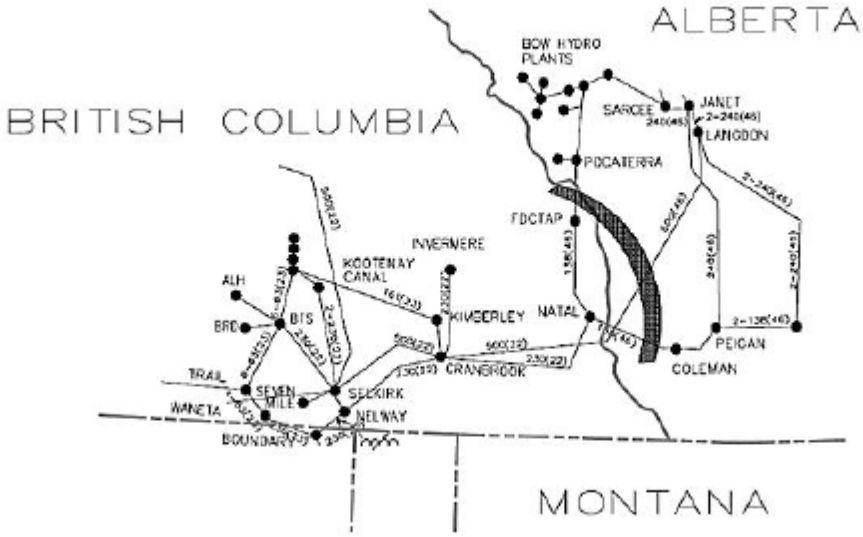

Figure 1.8: British Columbia and Alberta transmission systems

Two impacts of increased wind penetration are that it decreases the market price of electricity while increasing the requirement for contingency reserves coming from fast-ramping thermal generators. In Alberta's investor-driven deregulated market with high wind penetrations, the economics of new entry are not clear. Without enough hours where the price is sufficiently high to justify the capital, operating and maintenance expenses, new peak load generators will not enter the market. Lacking sufficient flexible generation to backstop against the variability of wind, wind generators may have their output curtailed and grid reliability is at issue. However, load following and wind firming services could be provided by fast ramping hydroelectric units which are relatively scarce in Alberta but plentiful in BC. In the work that follows, we assess the economic and environmental impacts of high wind penetrations combined with low intertie capacity in

the western provinces.

1.3 Research Questions

One of the most alarming aspects of renewable energy use in bulk power systems is the extent to which it is wasted. This waste stems from electricity that is generated but not used to meet demand, or it is wasted if one source of renewable energy displaces another. Electricity from renewable sources is also wasted if the use of renewable energy actually causes CO_2 emissions elsewhere in the system to remain unchanged or even to increase, or if the cost of using the renewable energy source greatly exceeds the associated benefits (including climate mitigation benefits). While the issue of wasted renewables is both real and significant, it is not often studied.

The potential for wasted renewables is rife in Western Canada's electric grids. Alberta's wind capacity penetration rate is the one of the highest in Canada at 8.5 percent, but its electricity generation portfolio is thermally dominated and, as a result, the system has a very limited amount of dispatchable capability or energy market flexibility (Hu, Kehler & McCrank, 2008).[8,9] Substantial levels of installed wind capacity and slow ramping extant generation are significant causes of wasted renewables.

None of the current research examines the economic impacts of the operational protocols proposed to manage high levels of wind energy in Alberta. Nor is there any assessment of the net CO_2 emissions associated with high wind penetrations in the Western provinces given the significant transmission congestion between Alberta and

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[8] $\text{wind capacity penetration rate} = \text{installed wind capacity (MW)}/\text{peak load (MW)}$

[9] Alberta is second to Nova Scotia with its wind capacity penetration rate of 12.3%.

BC. The main purpose of this dissertation is to investigate the role of greater grid interconnectedness on wind energy penetration. The three specific questions we study are discussed below.

Research Question One

The Alberta Electric System Operator (AESO) expects that by the end of 2012 approximately 1,575 MW of wind generation will be online (AESO, 2010b). The variability associated with wind generation output complicates the system operator's ability to balance supply and demand continuously and significant operational changes will be required to maintain system reliability. To this end, the AESO (2010c) developed a short-term set of tools for managing high levels of wind integration when changes in the supply/demand balance exceed the system limit. The methods to manage the system in the near term are:

- Energy market merit order dispatch for energy balancing rather than ramp rate requirements;
- Use of contingency reserves for managing wind ramp downs in excess of the system ramp rate; and [10]
- Curtailment, known in Alberta as Wind Power Management (WPM), to control wind ramp up events.

The cost of utilizing any of these tools impacts market participants unequally, in one case wind producers, in the other, extant conventional producers. For example,

[10] A detailed examination of the ancillary services markets including operating reserves can be found in section 2.5

changes in the costs of providing additional contingency reserves would be borne by the load, while WPM and over dispatching from the energy market merit order (EMMO) would affect power producers' revenues.

The choice of this particular set of tools necessitates abandoning other possible mechanisms. Notably, the AESO opted not to utilize over dispatching from the EMMO to cope with changes in wind output despite the fact that the EMMO is the primary method the system operator uses to balance supply and demand. Over dispatching involves moving up or down the merit order to meet the required system ramp rate with the caveat that the over dispatched offer would only briefly be in merit while the system is being rebalanced.

The purpose of the research is to compare the costs of exclusively using the EMMO in over dispatch to the tools chosen by the AESO to manage the system in the short run. Given that the short-term mitigation tools are invoked when net demand exceeds the system limit, how much flexibility must be introduced into the system – to obviate short-term mitigation measures?

Research Question Two

Alberta is expected to experience greater grid instability as wind penetrations increase. Extant generators cannot be used as a backstop against the variability of wind generated energy production due to their slow ramp rates. British Columbia's hydro generation is well suited to firm and shape Alberta's wind power production. The Province of British Columbia's *Energy Plan* (2009) and *Clean Energy Act* (2010a) require that BC Hydro achieve energy self-sufficiency by 2016 at critical water levels. In

addition, BC Hydro must acquire a surplus of 3,000 GWh of insurance energy, also at critical water levels, by 2020[11]. Ninety-three percent of the province's electricity generation must come from clean and renewable resources.

In order for British Columbia to be a viable firming resource, it must have sufficient generation capability to meet and exceed these constraints. However, this apparently straightforward question generates debate. Government and private power producers contend that BC Hydro has increasingly had to import power from other jurisdictions to meet provincial demand, implying the province is a net importer of energy thereby requiring more generating capacity to service domestic load and provide the insurance energy required. However, BC Stats provides evidence that the province has been a net exporter of electricity for seven out of the last 11 years. The discrepancy appears to lie in the data sources; BC Hydro, BC Stats and Statistics Canada produce data based on differing underlying assumptions.

Can British Columbia meet the self-sufficiency and clean energy requirements required by provincial legislation with its existing electricity generation capacity? If a supply gap exists, what is the extent of the province's dependence on imported electricity and/or domestic thermal generation?

Research Question Three

The electric systems of Alberta and British Columbia are natural complements. Alberta has a high wind generating capacity but the remaining assets in the

[11] In 2012, this was amended by the provincial government to require self-sufficiency at average water levels

predominantly thermal portfolio have low ramping capabilities. The combination of fast ramping wind and slow ramping conventional generation leads to a significant amount of wasted renewable energy as the system operator may curtail wind output to maintain system balance. BC is replete with fast ramping hydro assets. However, the province is dependent upon imports to meet domestic load. Ideally a truly integrated Western grid could benefit both provinces. Alberta could utilize BC's fast ramping hydro generation to firm its own wind production while BC can take advantage of Alberta's baseload coal units that must run to maintain minimum stable generation levels to save water in reservoirs for future generation. The degree to which the symbiotic relationship can flourish is dependent upon the level of interconnectedness.

Currently, the two provinces are linked by a transmission intertie with a low available transfer capacity. Do changes in intertie capacity between the two provinces affect wind integration when water levels are permitted to vary? Does this impact the cost of emissions reductions?

1.4 Methods

To address the research questions posed above, we use two different modelling approaches: a simulation model to evaluate the impacts of high wind penetrations in the Alberta grid and linear programming to assess grid integration in the Western electric grids.

Simulation

Simulation models are abstractions of real systems and are used to replicate the actual system. The model outputs represent estimates of the real outputs for the physical

system. In order to determine the effects of increased wind integration on grid reliability we model the decision process used by the system operator in discrete time periods. To simulate the Alberta electric grid, we created a stochastic and dynamic model that mimics the unit commitment and economic dispatch protocols used by the system operator to balance the grid in ten minute intervals over a one year time horizon. To reproduce the variability in wind output, we use a mean reverting model of wind generation. The mean and speed of reversion are estimated using a linear regression, while volatility is added through draws from a Weibull distribution whose parameters were estimated from over 368,000 historical data points.

Mathematical Programming Models

Linear programming models are a form of constrained optimization. Given a linear objective function and constraints, we can determine the optimal values for system variables. We use different mathematical programming models to address the last two research questions. To address the issue of BC's ability to be energy self-sufficient, we maximize generating revenue subject to generating and trade constraints and introduce a non-linear constraint on head height. In the case of the linear Alberta-British Columbia grid integration problem, we minimize the cost of serving demand in each province also subject to generator and transmission constraints.

1.5 Outline of the Thesis

The electric operating systems in Alberta and British Columbia are described in detail in chapter 2. Chapter 3 provides an analysis of the economic costs of grid instability under differing wind penetrations given thermally dependent electric grids. We

address the question of BC's energy self-sufficiency in chapter 4. In chapter 5, we study the impacts of water conditions and transmission capacity on emission reductions costs in the western electric grids. Chapter 6 concludes.

Chapter 2: The Alberta and British Columbia (Weakly) Connected Grids

2.0 Introduction

The magnitude of the impacts associated with integrating wind energy into electric grids is primarily a function of the supply mix in that grid and, to the extent that transmission is possible, that of adjacent jurisdictions. The asset mix for electricity generation varies across regions because geography, resource availability and political boundaries have largely dictated the evolution of electricity generation provincially. Alberta has abundant fossil fuel resources for electricity generation, while British Columbia is replete with mountains and river systems. This explains why the Alberta grid relies on coal and natural gas while the BC system is almost exclusively composed of hydroelectric assets. In the research and analysis that follow, we concentrate exclusively on electric grid operations in the two most western provinces – Alberta and British Columbia. In chapter one, we discussed the growth of wind capacity globally and detailed the increase of installed wind capacity in Alberta and British Columbia. In this chapter, we provide a description of the Alberta and British Columbia grids and their connections to each other and to the United States.

2.1 The Alberta Interconnected System

Alberta is located in western Canada between British Columbia on the west and Saskatchewan in the east. The province is replete with oil, natural gas and coal deposits and, as such, it was natural to develop a generation system that uses fossil fuels as its primary energy source. In 2001, Alberta became the first Canadian province to operate a deregulated electricity market.

History of Electricity Market Deregulation in Alberta

Prior to 1996, Alberta's electricity markets were regulated by the provincial government. Three utilities – TransAlta, Edmonton Power (EPCOR) and Alberta Power (ATCO) generated 90 percent of the province's electricity.[12] A small municipal utility owned by the City of Medicine Hat, non-utility generators, and other small power producers provided the residual ten percent of required generation capacity. Both ATCO and TransAlta are investor-owned utilities, while EPCOR is owned by the City of Edmonton.[13] EPCOR and Medicine Hat provided generation services for their respective municipalities, while ATCO and TransAlta were provided with franchise distribution areas.

Altalink, a wholly-owned subsidiary of SNC-Lavalin, purchased the majority of the province's transmission system in 2002 from TransAlta with the remainder retained by EPCOR and ATCO.[14] The responsibility for electricity distribution is shared by four vertically integrated utilities (TransAlta, EPCOR, ATCO and the City of Medicine Hat) as well as seven municipally owned systems.[15] Three large distributors (Calgary, Red Deer and Lethbridge) own the wires required to connect them to the rest of the network. The entire network is called the Alberta Interconnected Electric System (AIES).

Historically, large scale generators were regulated by the Energy Resources Conservation Board (ERCB) and the Public Utilities Board (PUB), while smaller generators were controlled by the Small Power Research and Development Act (SPRD

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[12] TransAlta was known as Calgary Power Ltd until 1981 when it formally changed its name to TransAlta.
[13] Edmonton City Council decided to divest EPCOR Utilities of its generation assets in 2009 creating a publicly traded entity known as Capital Power Corporation.
[14] In 2002, SNC-Lavalin received regulatory approval to purchase 12,000 km of transmission wires and associated substations from TransAlta.
[15] City of Calgary, City of Lethbridge, Red Deer, Cardston, Fort MacLeod, Ponoka, and the municipality of Crowsnest Pass.

Act). The ERCB ensured adequate reliability of the Alberta system, planned growth in capacity and approved any additions to either generation or transmission. The ERCB also played a role in the decommissioning of generating facilities. The PUB determined the regulated rates that the investor-owned utilities (IOU) could charge using a traditional rate base/rate-of-return approach. The criterion for approving capital additions was that the property would be "used or required to be used to provide service to the public within Alberta" (Province of Alberta, 2010b, p. 13). Rates of return were to be set to levels equivalent to those of non-regulated industries that exhibited similar risk structures. The costs were then allocated across the residential, industrial and commercial rates based on internal cost-of-service studies.

The daily operation of the market took place through a control centre initially managed by TransAlta. Large scale generators were stacked in order of their marginal costs and dispatched in this order to meet electricity demand. This method allowed the system controller to minimize costs while meeting provincial load.

The provincial government began deregulating the electric industry in the mid-1990s. There were three main reasons for the change in policy. The first was to provide competitive markets for a commodity that the government felt no longer needed to be regulated. Encouraging competition would not only drive down electricity prices as companies competed to sell their goods but it would also promote innovation in a way that regulated markets could not. The second reason for deregulation was to bring choice to consumers. A competitive marketplace would offer options to industrial, commercial and residential end-users – not only with respect to price structures but also with regards to new services. Finally, competition would allow smaller scale investors to build generating

capacity with newer, more efficient technologies. Under regulation there was little incentive for the three utilities to create smaller or more efficient plants (AESO, 2006).

The Electric Utilities Act

On May 17, 1995, the Electricity Utilities Act (EUA) was passed, thus heralding a new age for the Alberta electricity industry. This legislation came into force January 1996 and provided the government with the ability to deconstruct the previously regulated electric industry and provide a competitive market for end-users. The EUA separated distribution and transmission from the supply of the electricity. The EUA also created the Power Pool – a not-for-profit wholesale electricity clearing body. The purpose of the Power Pool was to operate a competitive wholesale market and dispatch generators. The EUA also stated that all electricity bought and sold in the province had to be exchanged through the Pool. The Power Pool was solely responsible for balancing supply and demand and providing an hourly electricity price. To ensure that the electricity market operated in both a fair and efficient manner, the government created the Alberta Market Surveillance Administration (MSA) as a watchdog agency with the ability to penalize market participants should it be required. With respect to transmission, the government stipulated that there would be equal and open access to the province's transmission assets, although the transmission system would be operated by a for-profit transmission administrator.

Stranded Benefits

With restructuring, the government needed to address issues of stranded benefits. Stranded assets refer to assets that were regulated into existence and whose costs were subsidized by the ratepayer. Once deregulation occurs, newer technologies enter and cause the existing assets to become uneconomic – or stranded. In Alberta, the converse problem

exists. The cost of electricity provided by existing coal fired units is inexpensive relative to new technologies. As a consequence, residential, commercial and industrial groups expected the costs of electricity to be lower prior to deregulation because additional higher cost new generation would be added in the future. If deregulation allowed the utilities to sell power at a market (rather than a regulated) price, the end-users would not receive the benefits of the province's low cost generation. The benefits to consumers would be stranded under deregulation. To aid with the transition to a competitive marketplace, the province required the existing owners of regulated generation facilities to provide low cost power to the distribution companies via legislated hedges.

Obligations and Entitlements: 1996 to 2000

The legislated hedges were practically implemented by flowing goods and payments between the generators and the distribution companies. Under the Power Pool system, some generators would receive a price in excess of their variable cost of production and at other times may not recoup enough revenue to cover their fixed costs. To aid in the transition to a fully deregulated market provincial regulation created a system of obligations and entitlements guaranteeing that generators received their fixed costs and end-users rates would remain approximately equal to variable cost of production.

Each generator was assigned a unit obligation amount (UOA) based on historic average availability for each hour between 1996 and 2000. The variable price was also forecast for each generator – this is the unit obligation price (UOP). If the Power Pool price was less than the UOP, there was no requirement for the generator to run. However, if the Pool price was greater than the UOP then the generator would need to provide the UOA of power. Each hour the unit obligation value (UOV) was calculated using the formula:

$$UOV = (Pool\ Price - UOP) \times UOA \qquad (2.1)$$

The unit obligation value was summed over all generators for each hour and redistributed back to the distributors according to their share of the load in 1996. This share distribution was maintained until the end of 2000. The transmission administrator also received some of the unit obligation value based on transmission losses.

The system of obligations covered generators' variable costs and ensured that distributors had access to the province's low cost generation. Equally important was the fact that the generating stations were conceived and constructed in a regulatory environment where capital costs were amortized over the life of the facilities, with these costs eventually to be recovered from ratepayers. The provincial regulation provided that the owners of the generators receive payment equal to fixed costs; known as reservation payments. The reservation payments were paid by the distributors to the generators regardless of whether or not the units ran in any particular hour. This system of legislated hedges and reservation payments ended with the Power Purchase Agreements (PPA) auction.

The Power Purchase Arrangements and Auction

The Balancing Pool was created to hold and administer the generation units that remained unsold at the end of the power purchase arrangement (PPA) auction (see below for the case of hydro assets). The legislated hedges were terminated in 2001 with the PPA auction that finally divested the electrical output of generating units built under provincial regulation from their owners. The intent of the auction was to sell off the output of each of the generating stations to other buyers in order to minimize the market power of any of the incumbent utilities where market power was defined "as the ability of suppliers of

electricity in Alberta to raise price above, and/or reduce supply below, competitive levels in order to realize a sustainable increase in profits" (Charles Rivers Associates, 1999, p.36). The unit's output would revert back to the owner at the end of the unit's base life.

The process commenced with the appointment of the Independent Assessment Team (IAT) which was composed of Price Waterhouse Coopers, Charles Rivers International and Market Design Inc. amongst other expert consultants. The role of the IAT was to determine the parameters of each of the power purchase agreements as well as the rules of the auction. Charles Rivers was responsible for conducting the auction.

During the initial stages of the auction process, the IAT developed an overall contract supported by various schedules outlining the costs and benefits to both the owner of the unit and the buyer. For example, schedule D defines the availability incentives for the buyer. Schedule E sets out the buyer's energy payments as a result of buyer initiated cold starts, warms starts and hot starts. Schedules F through N define similar payment schedules and responsibilities between owners and buyers. Owners were consulted by the IAT to ensure that the payment schedules would cover the operating costs of each of the units.

In August 2000 the provincial government put 12 units in the auction: Battle River, Clover Bar, Genesee, Keephills, Rainbow, Rossdale, Sheerness, Sturgeon, Sundance A, Sundance B, Sundance C and Wabamun. The maturity date of the power purchase agreements was the retirement date of the unit. HR Milner was withdrawn from the August 2000 auction due to uncertainties surrounding its coal supply at the time. The hydro unit was not auctioned and is held by the Balancing Pool. In part, the reason for not allowing the purchase of hydro output had to do with its concurrent responsibilities related to flood

control and water management. Electricity production was considered a tertiary role of the hydroelectric facilities.

In an effort to mitigate market power resulting from PPA purchases, the auction rules, as specified by Charles Rivers Associates (1999, p. 40), required that:

1. An owner was not allowed to bid on its own thermal PPA.
2. Total PPA capacity was required to be less than 20 percent of total capacity available in the auction (i.e., no more than two baseload PPAs).
3. A PPA holder is not permitted to hold both the Clover Bar PPA (peaking unit) and the Rossdale PPA (peaking unit).
4. A PPA holder is not permitted to hold both the Clover Bar (peaking unit) PPA and a baseload PPA.
5. A PPA holder could not hold both the Rossdale (peaking unit) PPA and two baseload PPAs.
6. TransAlta Utilities, owner of the hydro asset, was not allowed to bid on the peaking plants.

Table 2.1 provides the results of the power purchase agreement auction in August 2000, with the agreements coming into effect on January 1, 2001. At the end of the auction, five buyers purchased the rights and obligations to eight units representing 4,249 MW of capacity. The total revenues for the province amounted to over $1.1 billion. Column 7 represents the minimum opening bid for each of the assets in the auction. In the case of a negative valuation and negative winning bid, the Balancing Pool would pay the buyer the winning bid amount.[16] The payment would be provided in equal instalments over the life of the PPA.

[16] The PPA valuations are not derived from the value of the plant underlying the PPA, but from the difference between what the PPA holder expects to realize in selling electricity under the PPA and what the PPA holder expects to pay out under the PPA

Table 2.1: PPA Auction Results

PPA	Original Owner	Winning Bidder	Fuel	Capacity (MW)	PPA Term	Minimum Opening Bid (C$, mil)	Amount Bid (C$, mil)	Merit Order
Battle River	ATCO	EPCOR	Coal	666	2020	$50	$85	Baseload
Clover Bar	EPCOR		Gas	629.2	2010	-$96		Peaker
Genesee	EPCOR		Coal	762	2020	-$300		Baseload
Keephills	TransAlta	Enmax	Coal	766	2020	$50	$241	Baseload
Rainbow	EPCOR	Engage	Gas	93	2005	-$21	-$21	Peaker
Rossdale	ATCO	Engage	Gas	203	2003	$0	$0	Peaker
Sheerness	ATCO		Coal	756.2	2005	-$200		Baseload
Sturgeon	ATCO		Gas	18	2005	$0		Not Running
Sundance A	TransAlta	TransCanada	Coal	560	2017	$50	$212	Baseload
Sundance B	TransAlta	Enron	Coal	710	2020	$50	$295	Baseload
Sundance C	TransAlta	EPCOR	Coal	706	2020	$50	$269	Baseload
Wabumun	TransAlta	Enmax	Coal	548	2003	$25	$75	Baseload

Source: AESO (2006), Charles River Associates (1999)

Prior to the auction, EPCOR had 1,482.2 MW, ATCO 1643.2 MW and TransAlta 3,290 MW of regulated generating capacity. The auction completed divested ATCO and TransAlta of their generating assets. The unsold units (nearly 34 percent of the total auction capacity) reverted to the Balancing Pool. The remaining auctioned assets were distributed amongst EPCOR, Enmax, TransCanada, Enron and Engage Energy.

MAP I, MAP II and MAP III

Although the Balancing Pool was created to manage the output of the unsuccessful PPAs, it was not a long-term strategy. Following the recommendations of the independent assessment team, the output from the unsold units was divided into smaller pieces called ‘strips’. The sale of these strips was the central focus of the province’s Market Achievement Plan (MAP). The PPA strips constitute a fixed amount of output from a particular generating unit over a short time horizon (one to three years). This reduced the risk to potential buyers and reduced credit requirements for these small auctions. The MAP I auction was held in early December, 2000, just prior to the deregulation start date of

January 1, 2001. In the MAP I, bidders could purchase either flat (i.e., 24 hours a day) or peak (on peak hours only) power output strips for one-year terms for 2001, 2002 and 2003. There were 62 qualified auction participants and 45 buyers purchased contracts for more than 2,800 MW of power.

> The MAP I auction raised about $1.1 billion… MAP II, took place in 2002-2003 to sell the rights to the output associated with the three remaining PPAs whose short-term MAP I contracts would expire by 2003. Through this auction, the Balancing Pool sold its rights in larger chunks (100 MW for Sheerness and Genesee, and by the unit for Clover Bar). The Sheerness and Clover Bar MAP II contracts would expire in 2005, while the Genesee MAP II contracts would expire in 2006…. MAP III took place in late 2005/early 2006 to once again offer capacity associated with the Sheerness PPA, although this time the entire PPA was also offered for sale. The Sheerness PPA was purchased in its entirety by TransCanada for $585 million (AESO, 2006, p. 59).[17]

Fifty percent of Sundance B, which had been held by Enron, was resold to TransCanada, and the remainder was sold to AltaGas. The Balancing Pool determined Clover Bar PPA to be uneconomic and it was terminated on October 1, 2005. The Balancing Pool planned to offer the Genesee PPA for sale in whole or in parts on December 16, 2005, but the auction was postponed. The Genesee PPA auction depended on the:

> completion of the wholesale power market review by the Alberta Department of Energy and implementation of any resulting market modifications; consideration of any implications from currently pending federal greenhouse gas legislation; and assessment of market conditions such that a competitive sale will result in the Balancing Pool receiving a fair market value for this asset (Balancing Pool, 2007, p. 3).

The Balancing Pool continues to manage the output of the Genesee 1 and 2 units for the financial benefit of Albertans although it may decide to sell the Genesee PPA if the unit would receive its market value.

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[17] The Sheerness PPA was sold for $750 million over the reserve price. This was the result of more favourable market conditions, decreased uncertainty about the deregulated electricity market and legislative changes that encouraged additional auction participants.

The $2.2 billion in revenue generated from the PPA auction and the subsequent MAP auctions was redistributed to Alberta consumers via the Electricity Rebate Program. The program provided Alberta residents with a $40 per month rebate on their residential and farm electricity bills. Commercial and non-farm electricity users receive a rebate of $0.036/kWh.

Current Market Operations[18]

From January 1999 to 2003, the Power Pool was responsible for operating the wholesale competitive energy market. In 2003, the responsibility of providing the "safe, reliable operation of the provincial electric grid" was granted to the Alberta Electric System Operator (AESO, 2006, p. 7).[19] The system operator (also known as the system controller) is responsible for maintaining grid reliability by continuously equating system supply and demand at the lowest cost using economic dispatch. The North American Electric Reliability Corporation (NERC), a U.S. based federally mandated organization responsible for overseeing the reliability of the North American electric grid, defines economic dispatch as the "allocation of demand to individual generating units on line to effect the most economical production of electricity" (NERC, 2008b, p. 6).

Overseeing the reliability of Alberta's electric grid is the Western Electricity Coordinating Council (WECC). WECC is one of the eight coordinating councils that exist under the umbrella of NERC. Ensuring the fair, efficient and openly competitive (FEOC) market is the responsibility of the Alberta Market Surveillance Administration.

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[18] The bulk of the material for this section was written in 2011.
[19] The 2003 Electric Utilities Act, created the Alberta Electric System Operator (AESO), joining the responsibilities of the Power Pool and the Transmission Administrator into a single organization.

2.2 Alberta's Markets for Energy and Ancillary Services

To fulfill the system operator's obligations of balancing supply and demand and maintaining grid reliability and stability, Alberta operates two complementary markets: the energy only hourly market that is made up of many buyers and sellers, and an ancillary services market with multiple sellers but a single buyer – the system operator (AESO). The two markets operate separately but are not independent, as the price for operating reserves in the ancillary services market is a function of the energy market price.

In the energy market, electricity consumers and suppliers interact to determine the market price of electricity for each hour every day. Each seller has one or more source assets that are registered with the system operator – either as a generator or as an importer. The consumption side of the market is made up of sink assets – either load or exports. The sources and sinks are subject to all the market rules set by the AESO and monitored by the Alberta Market Surveillance Administrator.

The Alberta generation portfolio includes generating assets comprised of coal-fired units, natural gas, hydroelectric, biomass and wind technologies. The contribution of each generating type to total provincial generating capacity is shown in Figure 2.1.

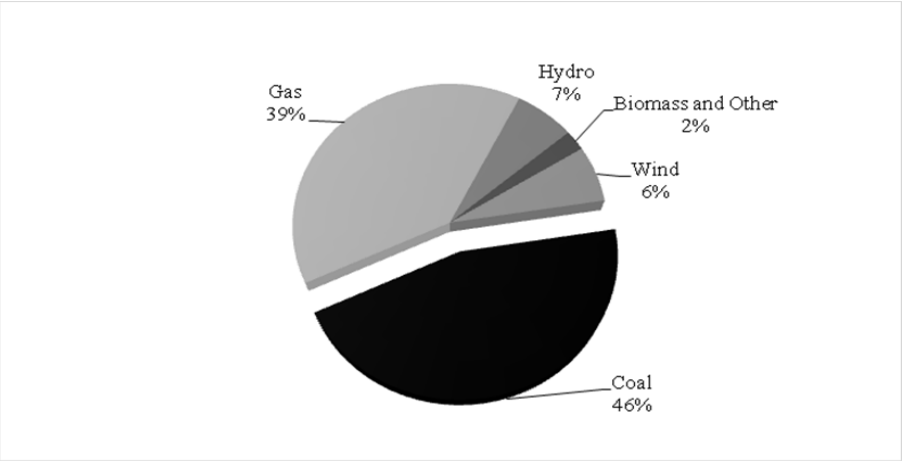

Figure 2.1: Alberta installed generation capacity by type (% of total)

Each of the generating sources must provide an offer (a price-quantity pair that represents a request to sell power) that accounts for the entirety of the asset's maximum stated capacity, or provide an explanation for why they are not able to offer in the full amount. That is, any deviation between maximum capability and available capability must be the result of an acceptable operational reason. In addition, generating assets must detail the ramp rate, time required for a generating asset to synchronize with the province's electricity system, the unit's minimum stable generation and any other information that is deemed pertinent by the independent system operator. This must be done by 12 p.m. of the day prior to the trading day.

Assets are permitted to offer their capacity in up to seven offer blocks. When the generator provides its offers in distinct blocks, they must specify whether each of the offered blocks is flexible or inflexible. The system operator is allowed to use all or a portion, of the offered volume of a flexible block to balance the system. An inflexible block requires a binary decision by the system operator: take all or none of the offered volume. We discuss the implications of inflexible blocks later in this chapter.

Of the 102 source assets in Alberta, 67 have an offer price for energy greater than $0/MWh (AESO, 2010b). Generally, offers of $0 are inflexible and cannot be dispatched off, such as baseload coal units that must operate at minimum stable generation levels. Up to two hours prior to the operational hour, T-2, a Pool participant who has submitted an offer may make an energy restatement, changing either the offered price or quantity. In the case of a quantity restatement, where the new quantity is less than the original offer, the AESO applies the reduction to the existing blocks in descending order – that is, the quantity will be reduced from the highest priced blocks first. The converse is true of an

increase in quantity – the AESO will apply the increased quantity to the lowest priced blocks first. These quantity restatements must be done as soon as practically possible. The Pool participant may also change the prices at which the blocks are offered. This may only be done up to two hours prior to the operational hour. If desired, sources can provide the AESO with a standing offer which holds price-quantity pairs constant for seven days.

Pool participants registered as sinks on the system may submit a bid — a request to purchase power. Each sink asset is permitted to offer in seven blocks; each block contains a price and quantity. Most of the rules for submissions of bids are the same as for those with source assets. Restatements of bids must be done as soon as practically possible. Any restatements that increase the amount of available capacity will be attached to the lowest bid block. Conversely, a decrease in the available capacity will result in the size of the most expensive block being adjusted downward. Price restatements may occur up until two hours prior to the operational hour. Imports and exports are also scheduled in the T-2 period and volumes may not be restated unless for an acceptable operational reason.

System Marginal Price

The system marginal price is determined by the last operating block required to meet system demand (e.g., see van Kooten, 2012, Chapter 11). The AESO distinguishes between Alberta Internal Electric System (AIES) demand, which is the total demand for electric energy and includes exports and associated losses, and Alberta internal load (AIL) that represents the total energy Alberta consumes, including industrial loads served by on-site generation, and the City of Medicine Hat's load served by that city's generators.[20,21]

[20] On site generation is used to serve behind-the-fence (BTF) load.

The energy market merit order (EMMO) is comprised of both bids from electricity consumers and generator offers stacked in ascending order. While some of the consumers will submit a bid, the largest part of the demand curve is perfectly inelastic (i.e., not responsive to price changes); only a small part (175-300 MW or 1 -3 percent) of demand is price sensitive (AESO, 2010g).

The system controller adjusts total energy output to meet AIES load by dispatching up or down the EMMO as required taking into consideration minimum stable generation levels and whether the offered blocks are flexible or inflexible.

Offers to Increase Supply

Flexible offer blocks are straightforward to manage. The system operator dispatches all or part of the offer volume as needed. If the offer block is inflexible but the offered volume is equal to or less than the increase in demand, then the inflexible block is fully dispatched on. However, if the block is inflexible and the offered volume is greater than required by the system operator, that block is ignored and the system operator considers the next available offer block in the EMMO. As soon as real-time demand has changed so that the full volume of the skipped offer block can be accommodated, the system operator dispatches off the higher block and dispatches on the inflexible block.

Bids to Reduce Demand

Bids represent the consumers' willingness to reduce the consumption of electricity at the bid price and can be either flexible or inflexible. Flexible bids allow the system

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[21] The City of Medicine Hat does not participate in Alberta's deregulated electricity market. From its inception, it has generated, transmitted and distributed its own electricity. Some local electrification cooperatives have also opted out of the deregulated electric system.

operator to reduce the sink's demand by all of, or a fraction of, the bid volume. Inflexible bids imply that the consumer is willing to reduce demand by all of the bid volume or none of it, but not a portion of the bid volume. In the case where the system operator is moving up the merit order and faces a flexible bid, then the system operator will direct the sink to reduce demand by the amount required to balance the system and the bid price will set the system marginal price. If the next available block in the EMMO was submitted as an inflexible bid then there are two possible outcomes. If the amount of energy required to balance the system is greater than the size of the inflexible bid, the sink is directed to reduce demand by the entire bid volume. However, if the amount of energy required by the system operator is less than the inflexible bid volume that particular block cannot be used. The sink will not reduce demand by less than the full amount of the bid volume – the definition of the inflexible bid. Thus the system operator skips over that block and moves up to the next available block until the point when the system operator can accommodate the full volume of the inflexible bid. Section 2.3 provides an example of the dispatch protocol used by the system operator.

Supply Surplus

During incidents of supply surplus where the next hour is expected to consist solely of $0 price blocks, the system operator will curtail import interchange transactions in that upcoming hour. If an excess supply condition persists, the system operator will reduce the dispatch levels of each of the flexible $0 blocks (excluding imports) on a pro-rata basis.

SMP and Pool Price

Every minute the last dispatched block sets the system market price (SMP). At the end of the hour, the average of the 60 one-minute SMPs determines the hourly Pool price.

All sources receive and all sinks are required to the pay the Pool price, also known as the settlement price.

2.3 System Operations in a High Wind Environment

For reliable and stable grid operation, the system controller must balance supply and demand continuously. Unresolved gaps between supply and demand can lead to blackouts that cascade throughout interconnected regions. The system operator manages system balancing with the objective of meeting demand at the lowest cost. This is true even in regulated electric markets.

System Operations with Operational Certainty and No Interconnections

Balancing the grid when all supply is 100 percent reliable, demand is constant and there are no imports or exports is a simple and straightforward exercise. Generators offer their energy into the system ahead of time, say two hours before the energy is required (T-2). The system controller dispatches a sufficient number of generators from energy market merit order (EMMO) until supply is equated with demand. By dispatching from the bottom of the merit order, the system operator ensures that the lowest price generators are dispatched first. The last dispatched generator is the supplier on the margin and sets the price. All generators that are dispatched will receive that price even though their offer may have been at a lower price. Demand has been met by the dispatched generators and the system is balanced. The intersection of the EMMO and the demand curve set the market price of electricity. A graphical depiction of the system balancing is given in Figure 2.2. In this example, the market clears when the price is $250/MWh and the equilibrium output is 150 MW. The marginal supplier set the equilibrium price of $250/MWh. All generators with offers less than $250/MWh will provide energy to the grid and receive the prevailing

Pool price.

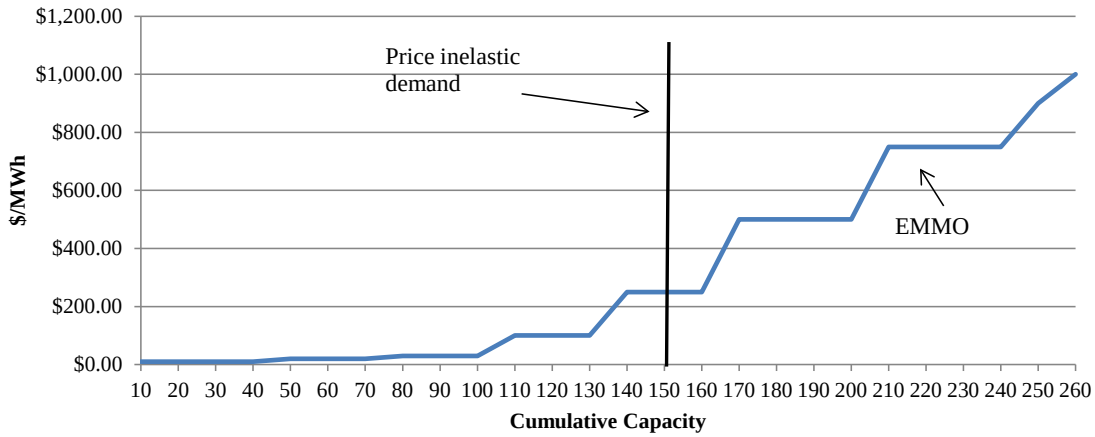

Figure 2.2: Supply and demand set the market price of electricity

Net Imports

The most straightforward complication we can add is to include net imports, which we define as imports minus exports. If net imports are positive then imports exceed exports and there is more energy entering the grid than leaving it. Conversely, if net imports are negative, then the volume of exports exceeds the imported volume. Both imports and exports are scheduled two hours prior to the operational hour. Imports enter the EMMO at the bottom of the supply stack with a zero price and are dispatched first. Exports are considered to bid in at $999.99/MWh. Imports and exports are treated as price takers because they are not dispatchable in real-time and are scheduled firm for the hour. Simultaneous importing and exporting of electricity in any given hour can, and does, occur if the interties permit.[22]

With no uncertainty regarding load or generator availability, the system operator

[22] Alberta can simultaneously import and export using interconnections with British Columbia and Saskatchewan. On a single interconnection in any hour, physical flows will be in one direction representing an aggregate net import position.

dispatches enough generation to meet demand given the amount of imported energy volumes. As net import volumes increase, the Pool price is reduced as the demand curve intersects the supply curve at a lower price.

Planned Maintenance, Forced Outages and Critical Failures

Conventional generators are reliable, providing dispatchable energy to the grid. Like most mechanical equipment, however, generators require maintenance; units are taken offline for annual maintenance, a period called turnaround. These turnaround periods are scheduled by the owner and advance notice is given to the system operator. Because the units are offline during turnaround maintenance, they generate no output and therefore receive no revenue. As a result, maintenance is typically scheduled for the shoulder seasons (spring and fall) when demand and price are low.

Even well-maintained machines can break down. When a generator goes offline (or 'trips') due to a mechanical failure, these events are known in the electric industry as forced outages. On the other hand, ‘de-rates’ occur when generators are online and available but are able to produce less output than stated by their nameplate capacity.[23] Generation technologies have differing levels of reliability. Table 2.2 below outlines the average forced outage rates (FOR) for differing generation technologies (NERC, 2011). The availability of generator types can be written as: *100 – FOR%*.

[23] Transmission lines can also be out of service and/or de-rated.

Table 2.2: Generator Available by Type

Generation Type	Forced Outage Rate (%)
Coal	5.66
Gas – Open Cycle	11.69
Gas - Combined Cycle	5.71
Hydro	5.85
Nuclear	2.34

When a generator that has been dispatched by the system operator goes offline unexpectedly, the system operator has to replace that energy to meet demand. The system operator uses contingency reserves to balance the system in the case of a forced outage, deploying sufficient reserve energy to balance the system in the short run and dispatching additional units from the EMMO to balance operations over the remainder of the hour.

System Operation with Wind

Adding wind generation to the system is tantamount to adding conventional generators with extremely high forced outage rates. With wind energy, rather than referring to the amount of time the unit is not operating, it is standard to report the percent of the time that wind was providing energy to the grid, known as the capacity factor. A wind capacity factor equals the wind power actually generated divided by the total wind capacity. Capacity factors in Alberta ranged from a low of 27.2 percent in 2006 to a high value of 40.5 percent in 2007.[24] Total installed wind capacity in the province has steadily increased from 333 MW in 2006 to 865 MW in 2011. A depiction of the wind capacities and wind factors is shown in Figure 2.3.

[24] Alberta's wind capacities are relatively high compared with other jurisdictions. For example, in the U.S. the average capacity factor averaged about 20% between 2002 and 2010.

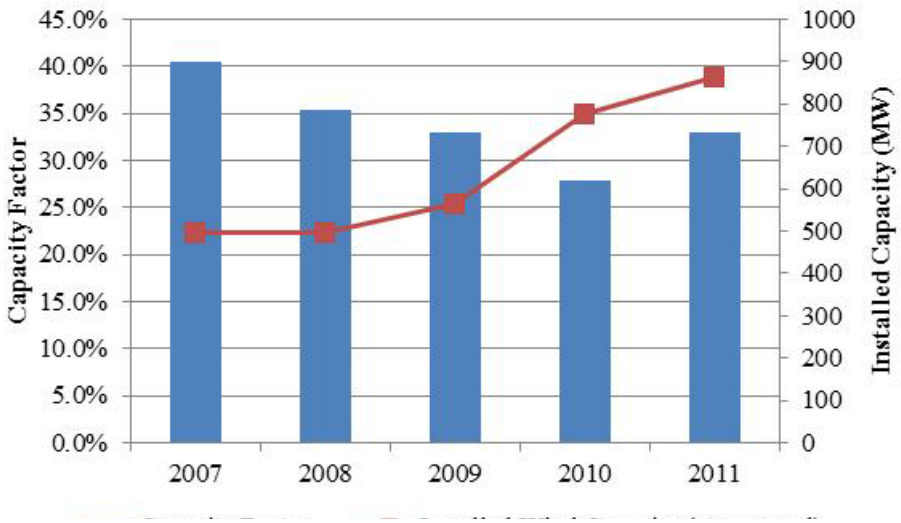

Figure 2.3: Alberta wind capacity factors and wind capacity additions

The amount of time that wind is available for generation is much lower than for conventional generation technologies. In addition to the low capacity factor associated with wind generated energy, there is also substantial variation in wind output. Average daily wind generation in Alberta for 2010 is shown in Figure 2.4.

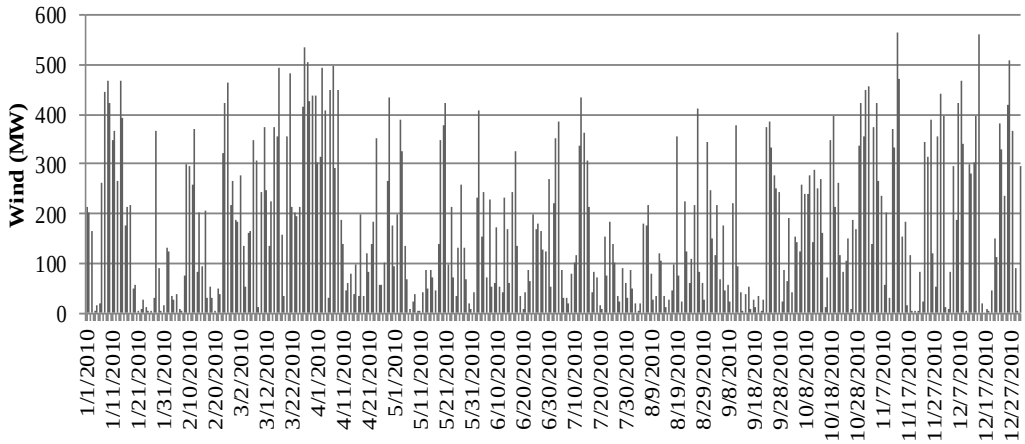

Figure 2.4: Average daily wind generation in Alberta

Wind is not dispatchable; the system operator cannot direct wind units to provide energy. When wind generated energy comes to the grid, the system operator must use it to

meet demand. Each time the wind increases (decreases) its output the system operator must react by decreasing (increasing) generation from another source. Typically other sources of energy include the EMMO and reserves. However, as discussed in Chapter 3, this could include newer energy technologies as well.

Dispatch Example

The following is a simple dispatch example with uncertainty given flexible and inflexible bids and offers, as provided in Table 2.3. Uncertainty in this example could come from the variation in demand or it can be caused by wind generated energy. The export bid represents the willingness to purchase 80 MW of energy, while bid 1 is an offer to reduce energy demand by 100 MW if the system marginal price is greater than the bid price of $80.

Table 2.3: EMMO Dispatch Example

Block	Flexible?	$/MWh	Volume (MW)	Cumulative Volume (MW)
Export Bid	Flexible	$999.99	80	605
Bid 2	Inflexible	$90	90	525
Bid 1	Flexible	$80	100	435
Offer 4	Flexible	$45	60	335
Offer 3	Inflexible	$15	25	275
Offer 2	Flexible	$10	50	250
Offer 1	Inflexible	$0	200	200

If system demand is initially 250 MW, then offers 1 and 2 are fully dispatched to meet demand and the system marginal price equals the highest price block required to satisfy the system load; in this case it is offer 2's price of $10. If demand increases to 260 MW then the system operator needs all of offers 1 and 2, but only 10 MW from offer 3.

However, since offer 3 is inflexible and the volume offered is greater than required, the system operator skips over offer 3 and dispatches 10 MW from offer 4. The system marginal price is $45. If system demand increases to 275 MW, the system operator can now use all of offer 3's inflexible block. The system operator dispatches off offer 4 and dispatches on all of offer 3; the system marginal price is reduced to $15. Suppose that system demand continues to rise and is 340 MW; then the system operator dispatches all of offers one through four and 5 MW from bid 1. The sink asset that provided bid 1 will reduce demand by 5 MW, and the system marginal price rises to $80.[25] Export volumes get filled at the Pool price that prevailed at the end of the operational hour.

2.4 Alberta Price Dynamics

As discussed in the previous section, there are many factors affecting the price dynamics of Alberta's competitive electricity market, including weather and expected and unexpected supply outages. Alberta demand consists of "78% industrial and commercial, 18% residential and 4% farm customers" (Alberta MSA, 2010, p. 15). Due to Alberta's high industrial load, which provides a more constant demand than that of small commercial and residential consumers, Alberta has a very high system load factor of just over 80 percent, where the system load factor is defined as the average demand divided by the peak load.[26] This results from Alberta's energy intensive economy. The high industrial demand is baseloaded and does not follow a diurnal pattern.

For other end-users, time of day is a significant factor. Alberta defines two separate

[25] Note that the prices are not $/MWh since the SMP is only effective until the next system operator dispatch. The Pool price is a $/MWh since it represents the price for 1 MW of electricity for 60 minutes

[26] By contrast, BC's system load factor is about 61%.

and distinct load periods – on peak hours and off peak hours. On peak (or heavy load) hours are defined as the period between hour ending (HE) 0900 and HE 2100 Mountain Time inclusive.[27] On peak is subdivided into AM and PM super peak periods. The corresponding hours for the two super peak periods are given in Table 2.4

Table 2.4: Definitions of Operating Reserve Time Periods

Period	Times
On Peak	HE 8-23
Off Peak	HE 1-7, HE 24
AM Super Peak	HE 6-8
PM Super Peak	HE 17-24 November, December and January
	HE 18-24 February - October

Source: AESO (2011d, p. 24)

Clearly, time of use affects Alberta electricity demand. The load profile of provincial demand exhibits a typical diurnal shape, higher during late afternoon, peaking in the early evening and falling thereafter as shown in Figure 2.5. Hourly demand exhibits a typical load profile with peak demand at HE 1800 and two load ramps - one in the morning between HE 0600 and HE 1000 and the other in the evening between 2100 and HE 2400.

[27] HE is the defined as the 60 minute period that ends the hour. For example, HE 0900 consists of the 60 minutes between 8:00 a.m. and 9:00 a.m.

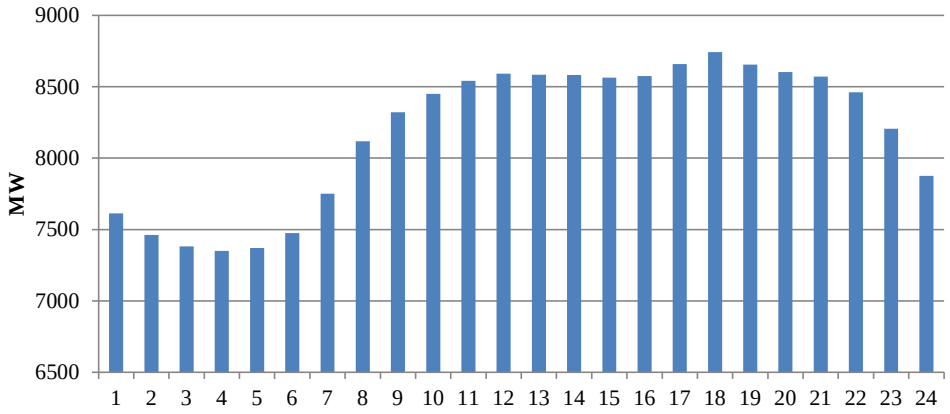

Figure 2.5: Average hourly demand (MWh)

Weather is another strong driver of demand, and therefore price and system demand are also dependent on the time of year. Average demands for each season are also shown in Table 2.5. The difference in demand between spring/summer and fall/winter is driven largely by heating and lighting needs.

Table 2.5: Seasonal Alberta Demand

Season	Average Demand (MW)
Spring	7,789
Summer	7,993
Fall	8,465
Winter	8,514
Annual Min	6,524
Annual Max	10,227

The Alberta market exhibits significant price volatility and concerns over the restructuring process were heightened by the substantial increases in the price of electricity in early 2001. However, following deregulation the average price of electricity fell dramatically, reaching a low of $22.37/MWh in February 2002. The cyclical nature of the deregulated price is evident. Supply constrained periods result in high prices leading to

investment; lower prices due to excess supply follow. Monthly average wholesale electricity prices are shown in Figure 2.6.

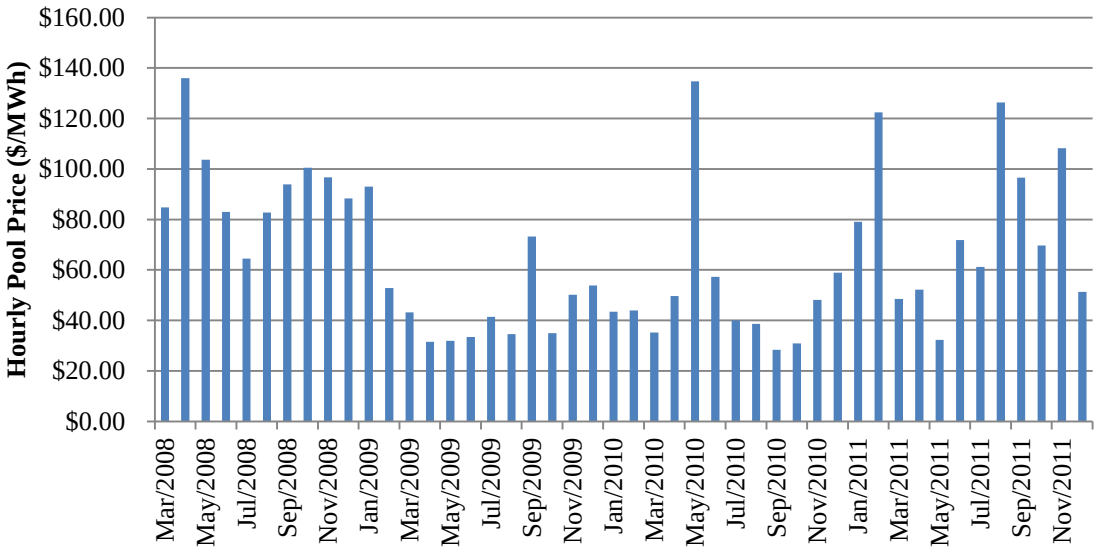

Figure 2.6: Average monthly pool price in $/MWh

Alberta's long-term adequacy measures showed significant pressure in 2011. Sundance 1 and 2 units, which provided 560 MW of capacity, were retired prior to their expected decommissioning date of 2017 as TransAlta deemed the repairs required to bring the units back online were uneconomic. The case went to binding arbitration and although the arbitrator agreed that the force majeure that caused the shutdown was valid, TransAlta's conclusion that repairs were uneconomic was not upheld. TransAlta is required to repair the units; they are expected online by the third quarter of 2013.

Genesee 3, a 466 MW coal unit, frequently trips offline due to mechanical failures. There is speculation that Keephills 3 which is the same equipment as Genesee 3 may also suffer from the same reliability issues. Plots of the average hourly supply cushion in MW (bar) and average pool price (line) for each month between March 2008 and December 2011 are provided in Figure 2.7. The average pool price clearly rises as the supply cushion

falls.

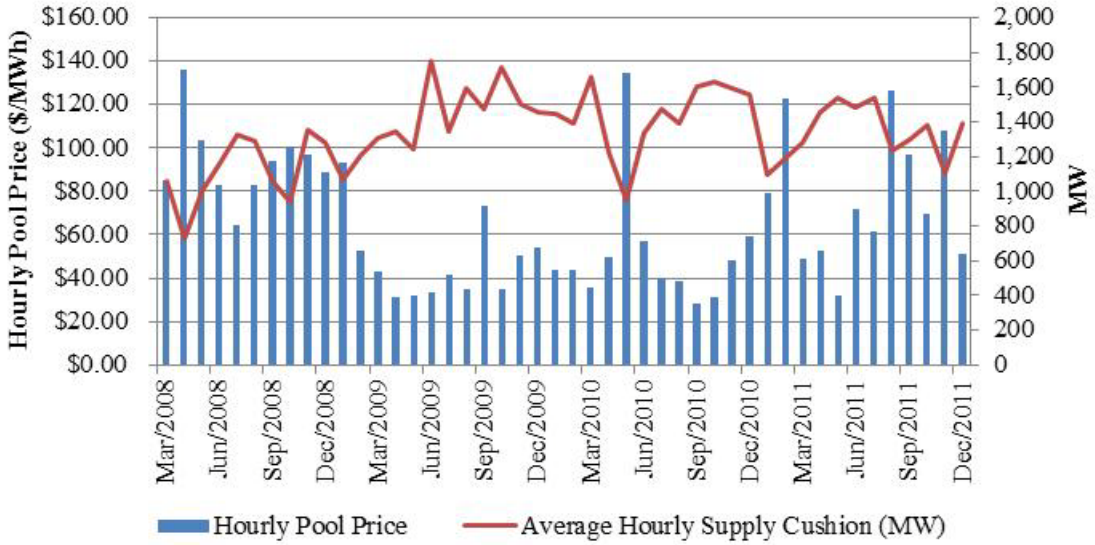

Figure 2.7: Average monthly supply cushion (MW) and Pool price ($/MWh)

The expectation is that supply adequacy metrics will be improved in the medium-term, however. Despite Genesee 3 failings, TransAlta's Keephills 3 unit is consistently providing 460 MW of electricity at present. Two 80 MW gas-fired Suncor units came online in 2012. A gas-fired Enmax unit and TransAlta’s Sundance 7 unit will increase provincial generating capacity by 1,600 MW when the stations are completed in May 2015 and December 2015 respectively.

2.5 Ancillary Market for Operating Reserves

While the energy market provides electricity to the bulk power system, ancillary services provide essential support to the energy market. Ancillary services consist of the operating reserves markets, transmission must run (TMR) operations, black start and load shed services. In the event of a system-wide outage, a black start generator can be started without an external electrical source. Load shed services (and remedial action schemes) are

automatic ‘trips’ of interruptible load sources to maintain the system’s frequency in the case of a trip on the Alberta –BC intertie. In the discussion that follows we focus on the two largest ancillary services markets: operating reserves and TMR. Operating reserves consist of regulating reserves and contingency reserves. Regulating reserves are used for automated generation control to manage small fluctuations in generator output and for frequency and voltage support. Contingency reserves are used to manage unexpected generator outages. There are two types of contingency reserves: spinning and supplemental. Spinning reserves consist of generators that are synchronized to the grid. In Alberta, spinning reserve may also be supplied by the interties. Supplemental reserves do not need to be synchronized to the grid and therefore, in addition to generators and the interties, load is permitted to participate in the supplemental reserve market. If dispatched, both spinning and supplemental reserve providers must position themselves to deliver their directed reserve volumes to the grid within 15 minutes and if deployed, reserve providers have ten minutes to deliver their full directed power volumes.

For all types of operating reserves, the AESO purchases both active and standby reserves. Active reserves are the primary source of additional short-term electricity. Standby reserves are only activated when a) active reserves have experienced a forced outage or b) inadequate active reserves were obtained. While active reserve providers may not participate in the energy market, generators offering standby reserves may also offer into the hourly energy market up until the point they are activated.

The amount of operating reserves the AESO procures is determined by reliability standards set by WECC and this amount changes throughout the day. As discussed earlier in conjunction with Table 2.4, the AESO divides each day into four periods. The AESO

obtains its active and standby operating reserves in the day ahead (D-1) market from Watt-Ex, an online trading site. At 9:00 a.m. (D-1) the markets at Watt-Ex open and the reserve providers submit offers. The markets close sequentially in 10 minute delays according to the schedule set out in Table 2.6.

Table 2.6 Operating Reserve Market Schedule

Time	Description
9:00	All Operating Reserve Markets Open
9:10	Active Regulating On/Off Peak Close
9:20	Active Regulating Super Peak Close
9:30	Active Spinning Close
9:40	Active Supplemental Close
9:50	Standby Regulating Close
10:00	Standby Spinning Close
10:10	Standby Supplemental Close

Source: AESO (2011i)

The active regulating market is open for 10 minutes, closing by 9:10. Every ten minutes a market closes; one hour later, at 10:10 a.m., all the operating reserve markets are closed. The characteristics of the participants in the operating reserve markets are shown in Table 2.7.

Table 2.7: Characteristics of Active and Standby Operating Reserve Markets, Alberta

Type	Provided by:	Number of Participants	Average On Peak Volumes (MW)	Average Off Peak Volumes (MW)
Active Regulating	Generators	8 (18 assets)	160-165	110-125
Active Spinning	Generators, Intertie	14 (42 assets)	235-260	170-185
Active Supplemental	Generators, Intertie, Load	17 (54 assets)	235-260	170-185
Standby Regulating	Generators	8 (18 assets)	110-140	110-140
Standby Spinning	Generators, Intertie	14 (42 assets)	105	105
Standby Supplemental	Generators, Intertie, Load	17 (54 assets)	35-45	35-45

Source: Alberta MSA (2009b)

Active Reserve Pricing

Active reserve providers receive two payments – a dispatch payment for standing ready and able to deliver its product and an energy payment when the energy is supplied to the grid. The dispatch payment for active reserve provision is based on the concept of equilibrium pricing (AESO, 2011d). Active reserve providers offer in their generation volumes at a premium or discount indexed to the Pool Price. Some offers are a fixed value less than the Pool price (e.g., Pool price - $10), and others are greater than the Pool price (e.g., Pool price + $15). The AESO has a bid price that represents the maximum price they are willing to pay to purchase reserves. The AESO posts its bid just after the market opens. As with the EMMO, the system operator continues to accept offers from the reserve merit order until sufficient volumes of reserves are activated. The marginal supplier is the last offer needed to fulfill the AESO's volume requirements. The equilibrium price of the dispatch payment is the average of the offer price of the marginal supplier and the bid price of the system operator. All reserve providers are paid the equilibrium price in addition to the hourly Pool price when providing reserve energy to the grid.

Active AM and PM super peak regulating reserves are also purchased at Watt-EX. Participants in the super peak active regulating reserve market offer in volumes for the AM super peak period, the PM super peak period or both, but they may not pick and choose hours within those super peak periods. The same volume of reserve energy must be offered across all hours of the super peak period chosen. When called upon, generators receive the Pool price as the energy payment in return for providing electricity to the grid.

Standby Reserve Pricing

Standby market prices are comprised of three parts: (1) a premium for standing

ready and able to provide reserves; (2) a price if they are dispatched to active service; and (3), if they are selected to provide energy to the system, an additional energy payment. The AESO sorts standby reserve offers based on the following blended price formula

$$Blended\ Price = Premium + (Activation\ \% \times Activation\ Price) \qquad (2.2)$$

The activation percentage is calculated from the historical activation rates of the different reserve products and is subject to change. The activation percentages as of October 2011 are given in Table 2.8.

Table 2.8: Activation Percentages

	Regulating	Spinning	Supplemental
On-Peak	1%	10%	10%
Off-Peak	3%	10%	10%

Source: (AESO, 2011h)

The lowest price offers that meet the AESO's volume requirements are accepted. The merit order for activation goes in ascending order according to the offered premium. It is unclear if all eligible standby reserve generators simultaneously place offers in the standby reserve market (D-1) and receive a premium prior to submitting an offer into the energy market before the deadline for energy market offers.

Transmission Must Run

Transmission must-run (TMR) refers to generation that is required to be online and operating in specific areas of Alberta where there is insufficient transmission capacity to support local demand and guarantee system reliability. The problem exists when there is sufficient generation in the province but due to transmission constraints the energy cannot reach load centres. Unlike many jurisdictions with locational pricing, Alberta has a

‘postage stamp’ system. The wholesale price of electricity is the same for all consumers regardless of where they are physically located. Internal transmission constraints led to the temporary use of TMR; the system operator will dispatch certain generators due to their location rather than based on the generator’s offer price.

The AESO procures TMR services for foreseeable and unforeseeable events from specific suppliers. Foreseeable TMR services cover normal operating conditions and planned transmission outages. Unforeseeable events correspond to issues that arise in real-time. Thermal TMR generators that are required to run and have an offer price less than or equal to the system marginal price receive the Pool price for their energy output. Out-of-merit thermal TMR providers are generators that would not normally be dispatched because their offer price exceeds the system marginal price. However, these generators are required to operate solely due to their location. Because they are required to run even when their offer price is greater than the Pool Price, the system operator provides a TMR payment. As out -of-merit thermal providers have no incentive to reveal their true marginal cost/price, the TMR payment is comprised of two parts: an energy payment and a capacity payment. The energy payment is based on the unit’s benchmark price. The benchmark price in dollars per MWh equals the heat rate multiplied by the fuel cost plus variable operating and maintenance charges. The heat rate in GJ/MWh equals the actual heat rate of the generating unit and the fuel cost is the AECO daily spot price for gas-fired units. Coal units provide fuel prices to the AESO in furtherance of the benchmark price calculation.

Costs for ancillary services including operating reserves and TMR services are recouped from load participants under a tariff. Any proposed tariff is submitted to the Alberta Utilities Commission for approval.

2.6 Wheeling

Alberta is connected to Saskatchewan's electrical system via an intertie that was designed to import and export 150 MW. However, constraints limit Alberta's average actual export capacity to Saskatchewan to 88 MW, while the available transfer capacity (ATC) for imports is, on average, 114 MW. More importantly, Alberta can connect with British Columbia. There are three lines: one 500 kV line from Cranbrook to Langdon and two Natal – Altalink 138 kV lines (see Fig 1.8). The maximum rated capacity between Alberta and BC is 1,000 MW, while the BC to Alberta line is rated at 1,200 MW. As with Saskatchewan, available transfer capacities differ considerably from the maximum ratings; on average, Alberta's export capability is about 390 MW while its average import capacity from BC is just over 500 MW. Enbridge will continue building the Montana-Alberta Transmission Line (MATL), which is a new intertie between Montana and southwest Alberta that would allow for up to 300 MW of bi-directional energy flows.

Planned internal transmission system upgrades in Alberta would have allowed an increase in the available transfer capacities along the interties. However, since the Alberta provincial election in October 2011, Premier Redford has placed the transmission upgrades under further review. The consequence of this delay is that the current export capacity of the province will not change. As no additional incremental energy can leave the province even if MATL becomes operational, the BC-AB intertie will be de-rated further.

Alberta's interconnection with BC is both vital and symbiotic. By exporting power in the evenings and through the night, Alberta is able to maintain its must-run coal units at their minimum stable generation levels and BC is able to store the water it would have otherwise flowed to generate electricity. During the day, BC may export electricity to

Alberta when the Alberta system requires it.

In addition to exporting electricity to BC, Alberta can take advantage of the BC transmission grid and export electricity into Washington, Oregon and California. This act of sending power across jurisdictions is known as “wheeling”. Under Federal Energy Regulatory Commission (FERC) Order 888, issued on March 4, 1997, jurisdictions wanting to trade electricity in other markets had to provide open access to their transmission. BC has met the FERC criteria and therefore Alberta is permitted to wheel electricity through BC and into the U.S. However, although there is open access to BC transmission, BC can dominate the transmission lines by using the Network Economy provision that allows BC preferential access to the transmission system for the purposes of serving domestic load. The intention of the provision was to ensure that BC could refuse wheeling by Alberta if BC’s tie line capacity was needed to meet domestic load. The regulation states that any non-firm point-to-point transmission (i.e. energy flows scheduled on an as-available basis) can be terminated in favour of Network Economy access to increase BC’s internal transmission usage and decrease Alberta’s access to the BC transmission system.

When transmission is available, Alberta exporters may choose to sell their electricity either at the Mid-Columbia pricing point in Washington state or further south at the California-Oregon border (COB) or Northern Oregon Border (NOB) hubs or further south to the California markets. However, like most of North America, transmission capacity constrains the trade of electricity. Massive infrastructure construction is required to allow unimpeded access across grids. There are several reasons why transmission capacities have not grown in proportion to generation capacity and demand. Most

obviously, transmission is difficult to site, expensive to build and requires considerable lead time. In addition, transmission constraints can benefit generators by artificially increasing the price of electricity in constrained markets.

2.7 British Columbia Electric Grid

There are two main differences between the Alberta and British Columbia systems: British Columbia's electric grid is regulated and predominantly hydroelectric while Alberta's grid is market based and thermally dependent. A map of BC's 500 kV transmission system and its connected generators was provided by BC Hydro and is shown in Figure 2.8.

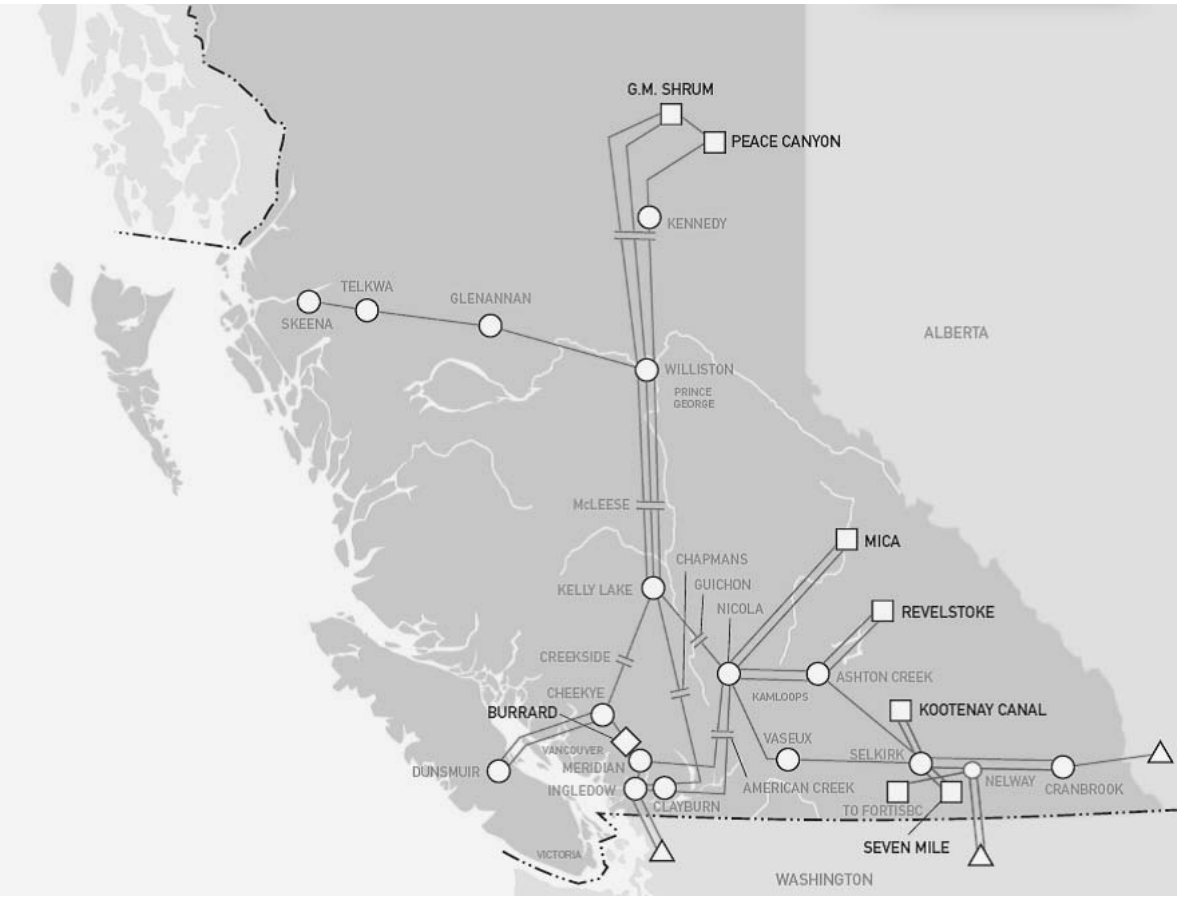

Figure 2.8: Map of BC's transmission grid and connected generators.

British Columbia's electrical system is regulated by the British Columbia Utilities Commission (BCUC) and run primarily by BC Hydro, a Crown corporation that provides generation, purchasing, distribution and sales of electricity services, and builds and maintains the province's transmission system. A detailed description of provincial generating assets will be provided in Chapter 4. In this section, we explore differences in how the Alberta and British Columbia grids operate.

The Alberta market system relies on price signals from the market to drive investors to build independent power projects. High prices are the result of a tight supply situation and signal investors that profit making opportunities exist and, thus, new generation is built. Conversely, low electricity prices are interpreted as adequate or excess supply conditions with little profit opportunity for new investment. This cycle has repeated itself several times in the Alberta electricity markets. In British Columbia, the electric grid is regulated; only transmission policy is clear and transparent.

Although there are clear export and import patterns, the unit cost of electricity in British Columbia is known only to BC Hydro. A wholly owned subsidiary of BC Hydro, Powerex, trades BC Hydro's surplus electricity including Canadian Entitlement energy from the Canada/U.S. Columbia River Treaty.[28] Proprietary trading strategies by Powerex are the oft-cited reason for the lack of a clear and transparent price signal in BC.

Growth in BC's generation capability has come from two sources: upgrades to existing hydroelectric assets and the acquisition of energy from independent power producers. Where Alberta allows the market price to signal investment conditions, British Columbia procures additional energy through power calls to independent power producers

[28] A detailed explanation of the Columbia Entitlement can be found in Chapter 4.

(IPPs). The power projects are submitted to BC Hydro under a variety of programs, including bioenergy initiatives, the standing offer program, clean power calls and the open call for power. BC Hydro selects proponents under each of the calls and will, upon completion of the project, enter into ten or twenty year bilateral contracts with the project developer to purchase the energy.

The standard purchase agreement between BC Hydro and power producers specifies that BC Hydro owns the emissions reductions credits and green attributes associated with the energy. The renewable energy component of the IPP energy is important to the province, because it is committed to self-sufficiency, to the generation of 93 percent of its energy from clean power source, and to a 33 percent reduction in greenhouse gas emissions by 2020. Whether BC can attain its self-sufficiency goal is addressed in Chapter 4. In what follows, we examine British Columbia's potential for export sales once self-sufficiency is achieved.

Exports

British Columbia can export electricity to Alberta or to the U.S. The Alberta market dynamics are fairly straightforward. BC, via its energy trading company Powerex, flows energy to Alberta when prices in Alberta are high. This tends to be during peak load hours, during periods of inclement weather or in periods of tight supply (i.e., forced outages). Conversely, Powerex will purchase energy from Alberta during the evening when the market price of electricity is low, reversing the flow of energy. The typical diurnal BC export profile is demonstrated in Figure 2.9. The shape of the export pattern remains fairly constant throughout the year.

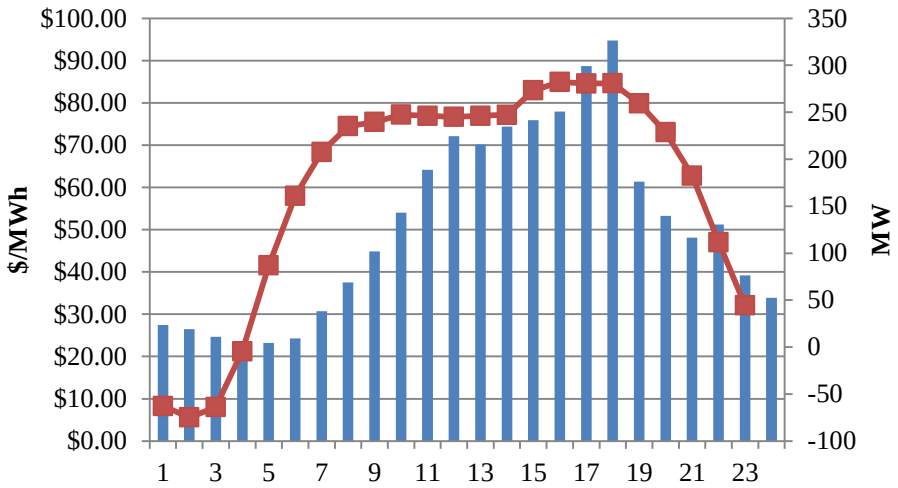

Figure 2.9: Diurnal BC export pattern with AB price profile

Mid-Columbia Market

British Columbia can export and import energy to and from the U.S., represented by the Bonneville Power Administration (BPA). BPA markets wholesale power from 31 large-scale hydro facilities in the Columbia River Basin, one nuclear plant and several small power plants. Twenty of the dams are operated by the U.S. Army Corps of Engineers and the remaining 11 dams are owned and operated by the U.S. Bureau of Reclamation. Installed wind capacity in the BPA's area has climbed to 3,000 MW with a total of 6,000 MW expected by the end of 2013. BPA also operates a significant amount of the high-voltage transmission in Idaho, Oregon, Washington, parts of Montana, California, Nevada, Utah and Wyoming.

Mid-Columbia (Mid-C) is one of the six western hubs for electricity trading and is served by 17 balancing authorities. The other western hubs are California-Oregon Border (COB), Nevada-Oregon Border (NOB), Palo Verde (PV), Four Corners and Mead. These locations are shown in Figure 2.10.

Figure 2.10: Trading points in the Western United States

Unlike Alberta's Pool in which all suppliers receive the market price, Mid-C and the other five hubs are bilateral markets with both day ahead and real time prices. In the day-ahead market, individual buyers and sellers agree on a price and volume and those two specific counterparties agree to trade at that particular price with delivery the following day. Many trades will occur in the day-ahead market and the price of each trade need not be the same, and prices may even be negative. In cases of excess supply of electricity, generators may pay consumers to take the product. This tends to occur at Mid-C because the region is comprised of high wind and hydro capacities that must run due to environmental considerations. Some non-dispatchable nuclear energy aggravates the problem.

The bulk of trades at bilateral markets, including Mid-C, are executed in the day-ahead market. Small volumes of balancing energy are traded on the real-time market.

Further south are the California-Oregon Border (COB) and Northern Oregon Border (NOB) hubs which are also bilateral markets. COB and NOB prices generally trade at a premium to Mid-C due to the increased cost of transmission from the Pacific Northwest. If transmission is available, BC (and Alberta) could wheel power to California markets.

The California Air Resource Board (CARB) continues to try to limit BC's ability to sell power into the state. CARB recently declared that BC Hydro is required to report greenhouse gas emissions associated with its generation. Greenhouse gas reporting standards are the first step in determining the amount of carbon offsets required under the state's cap-and-trade system that is set to begin in January 2013. BPA was exempted from this requirement based on its argument that, as a federal organization, it is not subject to state regulation. BC Hydro argued that Powerex, as a subsidiary of the Crown Corporation BC Hydro, should also be exempt. The BC Minister of Energy threatened NAFTA trade action against California if BPA were to receive preferential treatment for a commodity that is subject to NAFTA's national treatment standard – that is, BC Hydro/Powerex should have equal footing under the law. California has claimed that Powerex engages in resource shuffling – buying coal-fired generation and repackaging the stored water as clean electricity. If CARB's assertions are upheld, Powerex may be required to purchase carbon offsets for the energy it exports to California. This additional carbon charge may make energy sales to California economically infeasible.

California

California has mammoth electricity needs; summer peak system demand in 2010 was 62,459 MW (California Energy Department, 2011). The California ISO (CAISO) manages approximately 80 percent of state's load; the other 20 percent is managed by

municipal utilities and irrigation authorities. The asset mix is comprised of natural gas (53.4%), nuclear (15.7%), large hydro (14.6%), coal (1.7%) and renewables (14.6%).[29] Imports meet 31 percent of the state's electricity needs annually, with seven percent coming from the Pacific Northwest and 24 percent from the U.S. Southwest. California's interties allow 18,200 MW of imports, including 7,900 MW from the Pacific Northwest, 1,900 MW from Utah, 7,500 MW from the Desert southwest and 800 MW from Mexico. Flow of energy from the north of the state (NP15) to the south (SP15) is congested due to transmission constraints.

California is encouraging the growth in renewable energy markets by instigating aggressive renewable portfolio standards (RPS). Bill SB-107 passed in 2002, requires utilities to meet 20 percent of their energy needs from eligible renewable energy facilities by 2010. California utilities were unable to achieve that target. The State of California recently signed Bill SBX1-2 that postponed the 20 percent target until 2013 and escalated the RPS to 33 percent by 2020 by way of three compliance periods – 20 percent by the end of 2013, 25 percent by 2016 and 33 percent by 2020.

Utilities use renewable energy credits (RECs) to meet their RPS targets. One REC is equivalent to 1 MWh of energy from eligible renewable energy facilities. There are three categories of RPS-eligible transactions. Bucket 1 includes transactions of energy from projects that are interconnected with a California balancing authority, transactions from a unit directly connected to a California balancing authority, or transactions that are dynamically transferred into California. A minimum of fifty percent of RECs by the end of 2013 must be bucket 1 transactions, increasing to 65 percent in 2016 and 75 percent in

[29] Renewables include biomass, geothermal, small hydro, solar and wind.

2020. Firming and shaping transactions that provide incremental energy into California are eligible under bucket 2, but will decrease in importance over the compliance periods, comprising a maximum of 50 percent of RPS transactions that declines to 35 percent in 2016 and 25 percent in 2020. Bucket 3 transactions are RPS eligible transactions that are not included in buckets 1 and 2, including transferable renewable energy credits (TRECs). TRECs are the renewable attributes stripped from the energy component of the electricity production and do not require physical delivery of the commodity, thereby bypassing transmission constraints. The maximum amount of TRECs in the first compliance period is 25 percent, declining to 15 percent and then 10 percent by 2020. Because they bypass transmission congestion issues, TRECs may play an important role in meeting the RPS standard.

The reasons that California failed to meet the 2010 RPS target are attributed to the lag time in getting renewable projects online and the inability to get transmission built. CPUC (2009b) provided a preliminary report on meeting the 2020 RPS goals. There appears to be some significant and ongoing issues that have not been addressed. Fifty-one percent of anticipated renewable projects have been abandoned. A large number of long-term contracts with renewable energy producers will expire and, although some transmission upgrades are currently under construction,

> the magnitude of the infrastructure that California will have to plan, permit, procure, develop and integrate in the next ten years (to meet an RPS goal of 33 percent) is immense and unprecedented. Using past practices as a guide, the scale of the transmission and generation buildout will take at least 14 years if implementation starts today (CPUC, 2009b, p. 4).

Due to the difficulty in procuring bucket 1 RECs their price may be prohibitive. The state may need to increase the amount of eligible RECs under buckets 2 and 3 in order to meet the RPS on time.

There are two other possibilities that could allow California to meet the 2020 RPS. The high probability scenario is that California legislators will alter the definition of renewable technology to include large hydro projects. Another possibility, albeit one with a low probability of occurrence, is that WECC could form a regional transmission organization (RTO) which would permit all eligible renewable energy in the WECC region to be used to meet the RPS standard. Under the RTO scenario, BC Hydro would become eligible to sell Bucket 1 RECs to California.

2.8 Conclusions

The neighbouring grids of Alberta and British Columbia have complementary generation assets. Alberta has vast fossil fuel resources that provide reliable and inexpensive baseload power. British Columbia is able to store energy in the form of water behind its dams and could provide load shaping and wind firming capabilities. The two jurisdictions are joined by a small transmission interconnection. The ability of the two grids to work together efficiently is constrained by the capacity of the tie line. However, it is unlikely that the size of interconnection will increase. British Columbia cannot increase the intertie capacity unless Alberta upgrades its internal transmission infrastructure first. From the Alberta perspective, minimizing zero priced imports keeps the domestic price of electricity high and increases revenues to generators. Thus, without some coordination, interprovincial transmission capacity is unlikely to increase.

In the following chapter, we examine the effects of wind integration on system operations in the Alberta market. We study the economic main impacts of increasing wind capacity on system balancing costs.

Chapter 3: Estimating the Economic Costs of Increased Wind Penetration in Thermally Dependent Grids

3.0 Introduction

The large-scale adoption of wind turbine technology depresses the market price for electricity while increasing the need for system balancing. Using a stochastic simulation model of unit commitment and economic dispatch, we estimate the total system costs associated with increased wind capacity, accounting for the additional expense of larger contingency reserve requirements, the value of curtailed wind and the energy cost of meeting demand. With a 260 percent increase in installed wind capacity, system costs decline by 21 percent but area control error (ACE) events, which reflect deteriorations in grid stability, increase by nearly 43 percent. Relying exclusively on non-reserve generators to meet changes in net load increases system costs, but eliminates ACE events. The balancing issues associated with the variability of wind can be eradicated 99 percent of the time with 77 MW of fast ramping generation, even under the high wind scenario, although, the addition of new gas-fired peaking units also increases system costs at all wind levels.

3.1 History of Wind Mitigation Policies in Alberta

In general, wind power provides clean, renewable, low cost energy to the grid. In this regard, Alberta continues to see large and real potential for growth in wind capacity. There are approximately 20,000 MW of wind projects in the province's interconnection queue. However, as discussed in Chapter 2, the characteristics of wind power increase the difficulty in balancing the grid. In particular, the problems associated with wind generation include fast ramps (both increases and decreases), fuel source uncertainty, output variability and production that is uncorrelated with load (AESO, 2007).

The effect of the increased intermittency and variability resulting from higher wind power production is that more flexibility is demanded from the existing generating mix. Generators must be able to ramp quickly their production levels in response to changes in wind output. In the absence of generator flexibility, other mechanisms must be in place or else a situation of imbalance can persist resulting in grid stability issues.

In November 2005, due to growing wind energy production, the Alberta Electric System Operator (AESO) released a paper, *Incremental Impact on System Operations with Increased Wind Power Penetration*. Statistical methods and a simulation model were used in the discussion paper to determine the effects of higher wind capacity on system stability and reliability. The analysis focussed on the effect of increased wind power production on area control error (ACE) events. ACE events are tantamount to unscheduled flow on the Alberta-British Columbia intertie. The unscheduled flow (either positive or negative) is the result of a mismatch in supply and demand in the Alberta Interconnected Electric System. There are three key measures for ACE performance set by Western Electric Coordinating Council. These are:

- L10,
- Control Performance Standard 2 (CPS2), and
- Operating Transfer Capability (OTC) violations.

L_{10} requires Alberta to keep its unscheduled intertie flow under 60 MW for each 10 minute interval. CPS2 is the monthly aggregation of L_{10} events. CPS2 standards require that Alberta meet the L_{10} condition 90 percent of the time in any month. Finally, OTC violations represent the extent to which Alberta exceeds the available transfer capability plus a 65 MW

transmission reliability margin of the Alberta-British Columbia intertie. [30]

The North American Reliability Corporation (NERC) reliability standard BAL-001 requires that all balancing authorities meet two requirements with respect to ACE (R1 based on rolling 12 month periods and R2 based on 10 minute clock periods in a month) (NERC, 2007). If the reliability standards are breached in the U.S., then Federal Energy Regulatory Commission (FERC) may impose sanctions. Some Canadian provinces have approved the NERC standard but the method of sanctioning is different as FERC does not regulate Canadian entities. The province of Alberta is unique as it has not approved the NERC standards, but it is in the process of developing its own reliability standards that will subsequently be approved by the Alberta Utilities Commission (AUC). A breach of this standard would be subject to possible enforcement action by the Alberta Market Surveillance Administration and sanctioning by the AUC (either for a specified penalty or an administrative penalty).

To determine the effects of higher wind power production, the AESO analyzed four wind capacity scenarios:

- 254 MW (the amount of wind capacity in 2004),
- 895 MW (approximately 10 percent of peak load), [31]
- 1,445 MW (15 percent of peak load) and
- 1,994 MW (20 percent of peak load).

AESO (2005a) focussed on two key performance indicators: Control Performance Standard 2 and Operating Transfer Capability violations. The results from the statistical analysis

[30] The available transfer capacity on the AB-BC intertie is equal to the total transfer capacity minus the transmission reliability margin.

[31] AESO is in the process of evaluating the accuracy of forecasts made in the Incremental Impact report given that current installed wind capacity is close to the 895 MW of wind analyzed in scenario two of that report.

and simulation models allowed the AESO to draw several conclusions. They found that operational uncertainty may be relieved by accurate wind power forecasting. From the statistical analysis, the authors were able to conclude that the system would achieve some benefit from wind power development; in one scenario "wind power development increased by 5.69 times and the total wind power variability increased only by 3 times" (p. 14). However, the simulation model showed that any growth in wind capacity caused increased performance violations and reduced the system performance indicators. The key conclusion from the paper was that "operational concerns are present in the 895 MW scenario" (p. 15).

In 2006, recognizing that the system was fast approaching wind levels that would cause operational issues, the AESO instigated a 900 MW cap on provincial wind capacity. The cap was to remain in place while the system operator determined the appropriate measures necessary to achieve system reliability with increasing wind penetrations.

Market and Operational Framework

In 2007 the provincial government lifted the cap on wind coinciding with the system operator's report, *Market and Operational Framework for Wind Integration in Alberta.* The study concluded that, with a sound forecast of wind generation, the system operator could integrate wind energy using the following mechanisms:

- The Energy Market Merit Order (EMMO)
- Regulating Reserves
- Load/Supply Following Services
- Wind Power Management (WPM)

The energy market merit order is the primary method the system operator uses to balance supply and demand. Alternatively, short-term balancing energy can be provided from regulating

reserves. Similar to regulating reserves is the concept of load-following services. The AESO proposed the idea of a service that could provide energy to the grid within 20 minutes of dispatch. The size of load/supply following services would be a function of the wind generation forecast. In cases where the EMMO, regulating reserves and load/supply following services are inadequate for balancing the system, the system operator may need to limit or curtail wind generation, a process known in Alberta as wind power management (WPM).

The costs associated with the different management tools would be allocated so as to maintain consistency with the overall market policy. Wind forecasting costs are to be paid for by the individual wind power facilities as are the losses associated with the application of WPM protocols and any wind following services. The costs of procuring regulating reserves would be attributed to load via the tariff described in Chapter 2.

Short-term Wind Integration

While the Market and Operational Framework document (AESO, 2007) provided general operating plans for handling increased wind generation, the AESO required specific mitigation measures to support grid reliability given anticipated wind capacity expansions in the province. The *Short-Term Wind Integration Discussion Paper* (AESO, 2010d) outlines protocols for the operation of the Alberta grid with approximately 1,100 MW of wind capacity and was tested for sensitivities up to 1,500 MW. The AESO advocated three tools for managing wind energy in the province. The EMMO would remain as the workhorse for balancing the system. To the extent that ramping constraints of generators limit system balancing, regulating and contingency reserves could be used. When wind generation is ramping up faster than could be managed by the EMMO, wind power may be curtailed. Load-following services were omitted from the short-term mitigation plan as the market structure could not be implemented within the 18 month

timeline of the report.

The analysis in AESO (2010d) demonstrated the effects of increased wind energy production on system reliability measures. In particular, “any event 10 minutes or longer where the ACE was greater than 100 MW during that time was categorized as an ACE event” (AESO, 2010d, p. 13); in 2008, Alberta incurred 39 such events.. ‘Big ACE events’ are system imbalance situations that last longer than 30 minutes or the imbalance is greater than 250 MW. Wind ramps alone created a number of ACE and big ACE events. Wind was also complicit with other factors (load forecast error and changes in intertie scheduling) in creating additional ACE and big ACE events.

Following the assimilation of stakeholder comments, the Alberta system operator’s short-term recommendations on mitigation measures were finalized. The three tools approved for use were:

- EMMO dispatch for energy balancing rather than ramp rate requirements;
- Use of contingency reserves for wind ramp downs in excess of the system ramp rate; and
- Wind Power Management (WPM) to control wind ramp up events.

The idea of using over dispatch to increase the system ramp rate was discarded as those dispatched generators would provide energy to the grid over a very short time horizon, acting essentially as regulating reserve providers but without receiving the same level of compensation.[32] The AESO states that over dispatch “is not a practice that should be used on a ‘planned’ basis; a view based on the AESO’s interpretation of its mandate to promote a FEOC

[32] Recall from Chapter 2 that reserve providers receive an activation payment and a dispatch payment. In the over dispatch paradigm, generators would only receive the dispatch payment.

[fair, efficient and openly competitive] market" (p. 4).[33] The notion of procuring additional regulating reserves was also discarded in favour of contingency reserve provision. Regulating reserves were not considered as effective in mitigating wind ramp up events when compared to WPM. In addition the AESO believes that loss of wind speed should be considered a contingency event, so that from a fairness perspective, contingency reserves would be the appropriate mitigation tool.

Contingency reserves will be procured at times when wind ramp down events exceed the system ramp rate. These contingency reserves must be in excess of those specified by the North West Power Pool (NWPP).[34] Wind power management (limits or curtailment) would only be instigated at times when wind is ramping up (down) faster than the system can ramp down (up) generators without relying on over dispatch. The allocation for wind curtailments would be based on pro rata share of the overall system wind power limit.

Phase Two Wind Integration

The AESO expects that 1,575 MW of wind capacity will be installed and on line by the end of 2012[35]. As such, the short-term mitigation measures may not be sufficient to ensure system stability after 2012. Phase Two of the province's wind mitigation program addresses higher future levels of wind capacity and, unlike the short-term wind integration

[33] The Alberta government has dictated that the electricity and natural gas markets will operate according to fair, efficient and openly competitive (FEOC) principles.
[34] The North West Power Pool (NWPP) members operate their systems as a reserve sharing group. The NWPP then reports compliance performance to the WECC as a single group. Each member in the group is required to carry a minimum contingency reserve of 5% of its firm load served by hydro and wind resources, plus 7% served by thermal resources. The aggregation of this amount is that member's contingency reserve obligation (CRO).
[35] As of September 21, 2012 Alberta had 939 MW of installed wind capacity.

recommendations, it allows for significant market changes.[36] In conjunction with the discussion on mitigation measures, AESO (2010) provided analysis around each of the suggested measures based on simulation models over different scenarios: 1,575 MW by 2012, 1,700 by 2015 and 2,500 MW of installed wind capacity by 2020, and the "green" scenario of 4,000 MW of installed wind capacity by 2020.

Phase Two Wind Integration (AESO, 2010b) outlines three general approaches to mitigating the variability of wind. The first method is to accept the variability of wind as a system event much in the same way that changes in demand are handled. In this case the changes in wind supply can be dealt with through EMMO dispatch and increasing volumes of regulating reserves. In the longer term and with changes to dispatch response times, the AESO postulates that over dispatch may be acceptable to market participants. However, using the EMMO as a de facto ramping service could obfuscate price signals since all generators would receive the same energy price regardless of their ramping capability. Moreover, the use of over dispatch could cause a bifurcated merit order with most or all offers either at $0/MWh or at the cap of $1000/MWh. The over dispatch orders would only apply to generators with submitted offers greater than $0/MWh. Those generators with offers of $0/MWh would not be required to ramp up and down at the discretion of the system operator to follow wind production.

As generators required in the over dispatch protocol are only compensated for the few minutes they are required to provide energy to the grid, the compensation for over dispatched generators is minimal while wear and tear on the generating unit can be substantial. There would be benefits for generators to offer at $0/MWh thereby excluding the unit from over dispatch orders. At the other end of the market, units may want to be dispatched, even for a very short

[36] Initially the AESO had proposed studying short-term and long-term wind integration measures. Stakeholder feedback prompted the change of long-term to Phase Two, thus the different nomenclature.

time, if they were to receive a fraction of the highest price ($999.99/MWh). The end result of these two strategies is a market with most, or all, offers occurring at $0/MWh and $999.99/MWh.

EMMO dispatch would be used in conjunction with regulating reserves. From the AESO analysis, it is clear that for very high levels of installed wind capacity there would likely need to be a substantial increase in the quantity of regulating reserves required to mitigate the largest ACE events. The AESO found that, with total installed wind capacity of 4,000 MW, “the potential ACE events forecast in the dispatch simulation model suggest that upwards of 2,500 MW of regulating range may be required to mitigate the most extreme ACE events” (AESO, 2010b, p. 15). This amount of regulating reserve is well beyond the province’s intertie capacity and would have been nearly 30 percent of the average provincial load in 2010. With wind capacity at 861 MW, the AESO maintains regulating volumes between 110 MW and 225 MW. The AESO simulation results show that with 1,700 MW of wind capacity an additional 300 MW of regulating reserve could mitigate 67 percent of wind-related ACE events (AESO, 2010b). The use of currently available market reliability tools means that the costs of wind variability would be absorbed by market participants through changes in the cost of energy and ancillary service provision.

The second approach for managing wind variability in the long term is to provide support services to manage the issue directly. AESO (2007) and AESO (2010d) broadly address the concept of load following services. Load following services are similar to regulating reserve provision, except load following is over a slightly longer time horizon; where regulating reserves respond to intra-minute changes in load, load following occurs over the minutes-to-hours’ time frame. In AESO (2010b), the additional wind management tools of ramping and wind firming

services are considered.

Ramping services would address system ramp rate concerns outside the energy market structure. Since ramping services can be provided by a variety of technologies (traditional generation, batteries or demand response), there is an expectation that the market for ramping services would lead to a competitive outcome. This new ancillary service could be used to address wind ramps, but it could also address other system ramp issues including changes in the intertie schedule and the morning demand ramp. The costs associated with procuring these ancillary services could be attributed to the root cause; that is, the cost of activating ramping services for wind ramps would be directly allocated to wind producers. Alternatively, the ramping service could be defined as an ancillary service that would be paid for by consumers as an additional component of the transmission tariff.

A wind firming service has generators pooling resources to deliver a firm product to the market; eliminating the uncertainty associated with wind generation. As envisioned by the AESO, this service would be procured centrally; wind generation would not be firmed at individual facilities. While the market for a firming service is yet to be developed, the AESO speculates that the firming services would, for all intents and purposes, have wind acting as a dispatchable generator. As the service would be centrally regulated, diversity in production amongst wind producers would reduce both the necessity and cost of wind firming. As envisioned by the AESO, this firming service would be used exclusively for managing wind variations unlike the ramping service that could be used to manage demand ramps as well as wind ramping events.

Finally, the AESO could develop market rules that would require wind generators to act as conventional dispatchable generators, which would allow the system operator to manage wind

integration with existing reliability measures. An example is the must offer-must comply (MOMC) rule that would require wind generators to provide a specific quantity offer to the AESO and then provide that quantity of power to the grid. The MOMC rule could be applied to individual wind generators such that each producer must firm its own output. Conversely, the MOMC may apply to the aggregate output of wind generators, or the AESO could firm output on their behalf and attribute the associated costs to wind producers.

The AESO analysis determined the level of generating capacity that would be required to firm wind output in the different scenarios. Accurate wind forecasting reduces the need for firming services and the amount of firming service is dependent on the offers developed at T-2. Using historical wind profiles and assuming a 70 MW wind facility offers in full-output at T-2, the AESO estimated that up to 58 MW of open cycle gas turbine (OCGT) replacement generation would be required to satisfy the MOMC rules (AESO, 2010b, p. 30).

Since MOMC rules currently apply to all non-wind generators, it seems fair to impose this same rule on wind producers especially given that wind generators would have flexibility in how they firm up their output. However, while non-wind generators are subject to the MOMC rule, they are not required to firm supply in the event of acceptable operational reasons, generally speaking, unforeseen mechanical problems with the generating units. Holding wind generators to a higher standard would appear to violate the principles of fair, efficient and open competition. If lack of wind speed is deemed an acceptable operational reason (AESO, 2010d) then the MOMC rule would have little impact on mitigating wind variability.

Currently the AESO is working with stakeholders to determine the final recommendations for Phase Two Wind Integration. In December 2011, the Wind Integration Work Group produced an output report summarizing discussions and presentations that took

place since 2009 when Phase Two recommendations were first contemplated. The Phase Two final recommendation report is not yet available, although the AESO has indicated a spring 2012 release date or once stakeholder consensus on long-term wind management protocols is achieved.[37]

Policy Discussion

At the heart of Alberta's wind integration plan are the policy coherence and principles that are meant to guide any potential wind mitigation solutions. AESO (2010d, p. 10) sets out the following guidelines:

1. Any potential suite of wind integration tools must ensure the safe and reliable operation of the system.
2. Market solutions are preferable to administrative solutions given that the energy market merit order is primarily a tool for balancing energy requirements on the system.
3. All generation should be treated fairly while recognizing their unique characteristics.
4. Ancillary services are a tool to protect the system from events that cannot be reasonably controlled.

The fourth point is somewhat controversial: Can the intermittency in generation that arises from wind speed changes be controlled? In the short term, the system operator will continue to use existing control methods to deal with wind variability. The EMMO will be used to balance energy, while contingency reserves and wind curtailment will handle more severe wind ramp down and ramp up events, respectively. Contingency reserve costs are passed on to consumers as an additional component of the province's transmission tariff as described in Chapter 2. When wind power management is instigated, the curtailment or limits on wind

[37] As of September 21, 2012 the Phase Two Final Recommendation Paper has not been released, although AESO employees have indicated that it will be available imminently.

generation represent lost revenue to wind producers.

The general consensus in the literature has been that higher wind penetrations lead to greater balancing costs in the form of increased operating reserve requirements (Holttinen, 2004; Doherty & O'Malley, 2004; Holttinen, 2008). However, over production of wind energy associated with increased wind penetration is a growing concern. In energy surplus situations, wind generation may be curtailed to eliminate excess supply, although the condition under which curtailment may occur varies across balancing authorities. For example, Texas has a ramp rate limit of 10 percent per minute of online installed wind capacity, and Alberta has a variable wind power limit that is based on the system ramp rate of 600 MW/hour (Wan, 2011; AESO, 2010b). As wind capacities increase, the amount of curtailment is also expected to rise and the value of these wasted renewables is not generally incorporated in estimates of balancing costs.

The current research investigates the ability of a deregulated and thermally dependent electric grid to balance wind energy using Alberta as a case study. How does the balancing protocol affect system costs and grid stability? What impact does wind capacity have on contingency reserve requirements? Does the growth in wind capacity provide a rationale for additional fast ramping gas-fired units? To answer these questions, we created a stochastic simulation model of unit commitment and economic dispatch. We use generator offer curves, the ramp rates for individual generators and historic wind generation data to estimate costs and contingency reserve requirements, and to assess grid reliability using area control errors as a proxy measure.

3.2 Literature Review

We take a unique approach to estimating the balancing costs associated with wind integration by explicitly modeling the unit commitment period, economic dispatch protocol and

contingency reserve requirements in a deregulated grid characterized by significant generator inflexibility. We incorporate generator offer curves rather than production cost estimates, use the actual ramp rates of individual generating units and add stochastic wind generation for a realistic simulation. Offer curves may better describe the range of operating costs faced by generators over the range of outputs, unlike a linear production cost estimate.

Li & Kuri (2005) determine the impact of increasing wind energy penetrations on spinning reserve requirements over one week using a one hour resolution. The authors simulate the grid using a 30-bus test system with eight non-wind and two wind generators. The non-wind generators are constrained by slow ramp rates and minimum up and down times and spinning reserve is a function of excess online generation. They find that, as a result of wind variability, spinning reserve requirements necessitated additional units to be part-loaded to ensure sufficient reserve quantities. Total system costs increase as wind penetrations increase.

GE Energy Consulting (2005) examine the impacts of increased wind penetration on all aspects of the New York state grid using a minute-by-minute power flow simulation model. Although the spot market price of electricity fell as wind penetration increased, the effects on system operating costs depended upon the flexibility of the generators. When the expected value of wind energy is zero, too many generators are dispatched in the unit commitment time frame leading to increased system costs. Accurate forecasts of wind (or the corollary, generator flexibility) resulted in lower system costs.

Doherty, Denny & O'Malley (2004) consider the impacts of increasing wind penetration in the Irish grid with two different unit commitment timelines – one hour and 24 hours prior to the operational hour. In addition, they examine a competing scenario in which wind energy is used to reduce the fuel costs of the extant generators. Using a deterministic model, they calculate

the costs of reserves per year and find that costs of reserves are higher with wind energy than without any wind generation. Forecasting wind one hour ahead provides the lowest reserve costs when compared to day ahead forecasting or the fuel saver approach. The authors draw the conclusion that the choice of balancing protocol is critical in reducing costs associated with increased wind penetrations

Ummels, Gibescu, Pelgrum, Kling and Brand (2007) develop a unit commitment and economic dispatch model to examine the impacts of wind generation in the Dutch system. The system is characterized by generation inflexibility due to the significant number of combined heat and power units where production costs are based on fuel costs. Unit commitment and dispatch are optimized over 15 minute intervals to minimize operating costs. Although ramp rates are not an issue, they find high levels of reserves are required and a significant amount of wind curtailment occurs.

3.3 Simulation Overview

In the analysis that follows, we investigate the costs of balancing the grid under high wind penetrations given a thermally dominant generating portfolio. Our simulation follows the protocol outlined by the Alberta Electric System Operator. We use two time frames in which to balance the system, T-2 unit commitment and intra-hour economic dispatch. The simulation model is over a one-year horizon, with balancing occurring every ten minutes or 52,560 times during the course of a single model run. The time horizon corresponds with that of reserve deployment.

Unit Commitment

In the unit commitment period, the system operator forecasts the electric demand for the province, the Alberta Integrated Electric System (AIES) load. Hourly forecast AIES load data

are available from AESO (2011g). In Figure 3.1 we plot average hourly AIES load (dotted black) against the load forecast (solid grey), with the difference between forecast and actual load represented by bars. Note that the actual demand is always at least as great as the forecast. The largest error (~30 MW) occurs at near the average system peak of 8,600 MW.

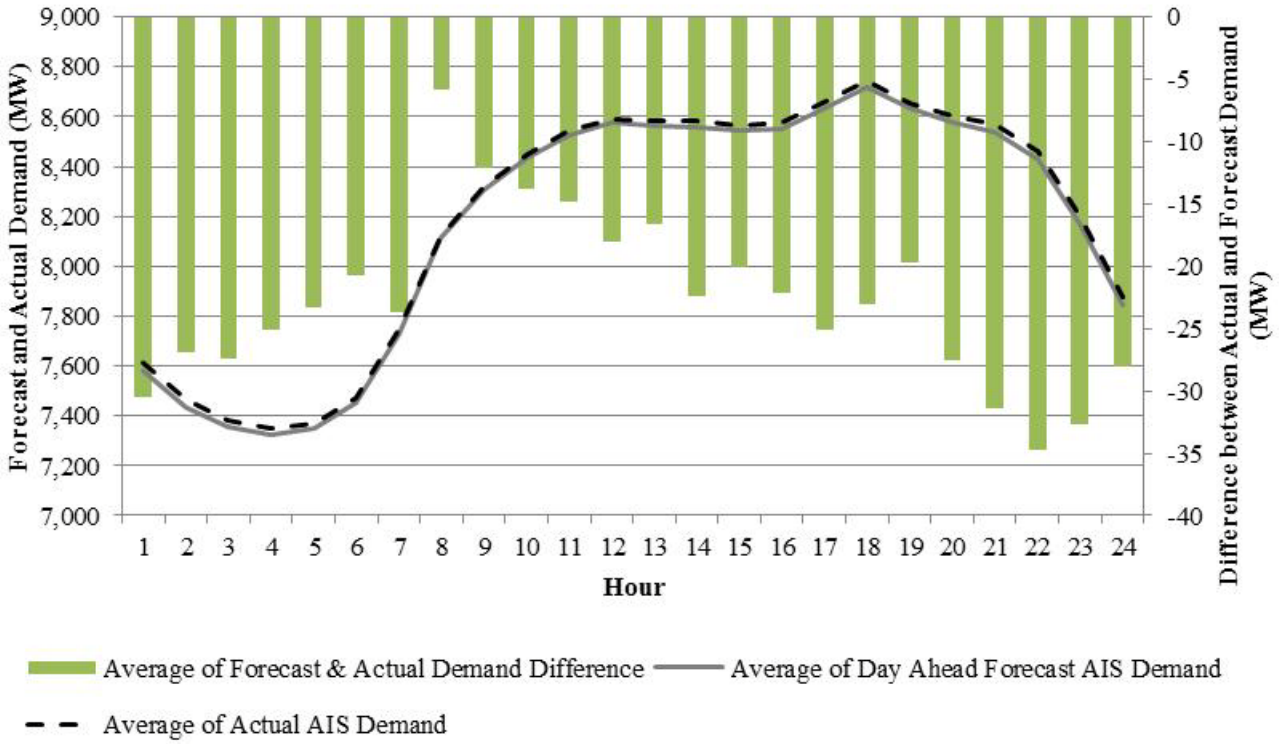

Figure 3.1: 2010 Alberta hourly average load and forecast

The forecasted AIES demand plus any scheduled exports must be met by a combination of conventional dispatchable generation from the EMMO and net imports to the province, as well as any expected wind generation.

EMMO

The EMMO is set at T-2 and the process for submitting generator offers is described in Chapter 2. The thermally dependent generating portfolio is based on the Alberta system, which by capacity consists of coal assets (46%), gas-fired units (39%), hydroelectric (7%), biomass

(2%) and wind (6%). Each of the generators and importers are required to provide hourly offers for their total available capacity for each hour of a 24 hour period. Offer prices may lie anywhere between the price floor ($0/MWh) and below the cap ($1000/MWh), although 80 percent of the offers are less than $125/MW. To create the EMMO for the simulation, a typical supply day was chosen; in this case October 15, 2010 was determined to be a representative of day with a typical number of generator outages. The data set, available directly from the AESO (2011g), includes all offers and bids for all sources and sinks including exports and imports which are designated as such. Because net imports are modeled separately, imports and exports details were stripped from the series. The remaining offers (and bids) were sorted first by hour and then in ascending order according to price. The result was 24 individual series representing the supply stack for each hour of the day.

The resulting set of 24 offer curves, one for each hour of the day, form the EMMO in both the unit commitment and economic dispatch models for each of the 365 days of the simulation. Figure 3.2 shows the energy market merit order for a typical off peak and on peak hour. The difference between the two curves is due to different offer strategies, greater generator participation in the reserve markets and higher net imports during the on-peak period.

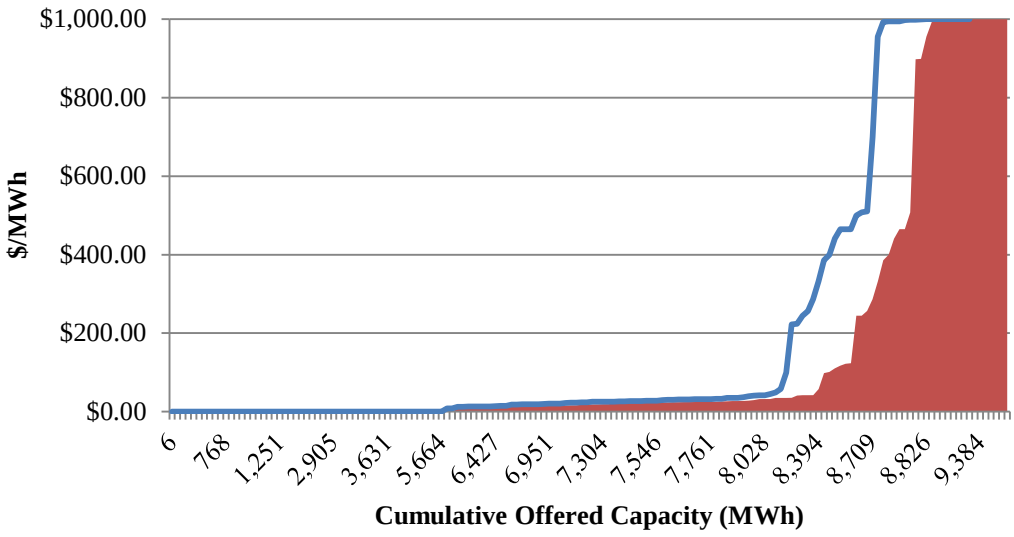

Figure 3.2: Generator offer curves for a typical off peak and peak hour

Ninety percent of the generating assets have a ramp rate of 15 MW/minute or less, although a review by AESO (2010b) found that "for both coal and gas units the average ramp rate observed was less than 5 MW/minute" (p. 13). A distribution of generating unit ramp rates is provided in Table 3.1.

Table 3.1: Distribution of Ramp Rates

Ramp Rate (MW/Minute)	≥30	25-30	20-25	15-20	10-15	5-10	≤5
Number of assets	4	1	1	0	9	24	28

Source: (AESO, 2010b, p. 13)

Exports and Imports

Exports and imports are also set in the T-2 period. When net imports (imports – exports) are positive, the system operator requires less energy from the EMMO to meet demand. For the purposes of this model and following AESO modeling practices, we assume a single interconnection to an adjacent grid and use 2010 actual hourly import and export volumes from AESO (2011g).

Economic Dispatch (Intrahour)

Within each hour, the system is balanced every ten minutes given the change in net load, which is the difference between load changes and wind output over the ten minute horizon. If the change in net load is less than the system's ramping limit – 100 MW per 10 minutes – then the system operator dispatches up (or down) the EMMO for balancing. If the system ramping limit is exceeded and an excess supply condition exists then wind is curtailed. Conversely, if the system ramping limit is violated and an excess demand situation occurs than contingency reserves are dispatched. Curtailment and contingency reserve dispatch are only used to reduce the change in load to the system limit of ±100 MW. Once the limit is reached, changes in EMMO dispatch must be used to manage the remaining system imbalance. An ACE event occurs when generators do not having sufficient ramp rates to meet changes in net load.[38]

We examine the ability of Alberta's thermally dominated system to manage integration of wind energy under four wind scenarios: 695 MW (base case), 1.1 GW, 1.5 GW and 2.5 GW of installed wind capacity. The only change across scenarios is the amounts of wind generation and available contingency reserves – the rest of the system (EMMO, demand, net imports) are held constant to isolate for the effects of wind on balancing costs.

3.4 Model

To analyze the impacts of wind variation on economic costs in a realistic setting, we simulate grid operations using both a unit commitment and economic dispatch model to balance the system. The unit commitment (UC) component dispatches sufficient generation to meet forecasted load net of expected wind generation and scheduled net imports, while the economic

[38] We follow the short-term protocols outlined in AESO (2010d). The Alberta system operator contends that, in general, the extant generators can ramp 100 MW every ten minutes.

dispatch (ED) simulation adjusts generator output to meet any intra hour changes in load and wind.

In the unit commitment model, for every hour *h*, the system operator directs units, denoted n, to provide their offered output ($Q^*_{n,h}$) such that the total amount of energy dispatched equals forecasted load requirements (L^*_h) net of expected wind generation (W^*_h)and net imports (I_h) where *N* is the total number of non-wind units. This can be written as follows:

$$\sum_{n=1}^{N} Q^*_{n,h} = L^*_h - W^*_h - I_h \qquad (3.1)$$

There are no ramping constraints in the unit commitment model as all generators receive their dispatch instructions two hours prior to the operational hour and there is sufficient time to ramp to their directed output levels.

Generators offer ($Q^*_{n,h}$) which must be less than their maximum capability,C_n, in any hour *h*, written mathematically in equation 3.2.

$$Q^*_{n,h} \leq C_n, \forall n, h \qquad (3.2)$$

We impose a similar constraint on our single wind generator. Forecasted wind output in each hour (W^*_h) must be less than the maximum installed wind capacity, $\mathrm{W_{max}}$.

$$W^*_h \leq W_{max} \qquad (3.3)$$

We denote actual generated output as $Q_{n,h}$ for conventional dispatchable generators and W_h for the single wind generator. Although there are times when generators may draw power during start up, in this model we do not allow a negative amount of output from any generator. The non-negativity constraints are written mathematically as:

$$W_h \geq 0, \forall\ h \qquad (3.4)$$

$$Q_{n,h} \geq 0, \forall\ n,h \qquad (3.5)$$

In the economic dispatch portion of the model, the system controller is managing the fluctuations in net load change within ten minute intervals, *t*. This is expressed mathematically as:

$$\Delta L_t - \Delta W_t \qquad (3.6)$$

where ΔL_t is the change in load over the ten minute interval while ΔW_t is the change in wind generation over that same period. We assume that the system can accommodate at most a 600 MW change in net load in any one hour, or 100 MW over a ten minute interval. Any net load changes are reduced to ± 100 MW through the deployment of sufficient contingency reserves in shortage situations or the use of wind curtailment in excess supply conditions. Generating units are then directed on or off in merit order, beginning with last dispatched generator in the previous ten minute period to eliminate any remaining supply gap. A generator is constrained by its ramp rate (R_n) that specifies the maximum output change in any interval:

$$\left|Q_{n,t} - Q_{n,t-1}\right| \leq R_n \qquad (3.7)$$

Area control error events occur if the next available generator in the EMMO does not have sufficient ramping capability to meet the required change in output. We calculate the ramp time required to avoid incurring an ACE event as:

$$\frac{min(offered\ volume, |\Delta L_t - \Delta W_t|)}{R_n} \qquad (3.8)$$

If the required ramp rate is greater than 10, so that the generator would take more than 10 minutes to ramp to the required output, an ACE event is registered. To rectify the imbalance sufficient contingency reserves are directed on (or off). A summary of the balancing instructions

is found in Table 3.2.

Table 3.2: Summary of Contingency Reserve and Curtailment Protocols.

Change in Net Load	Protocol Initiated
- $(\Delta L_t - \Delta W_t) \geq 100$	Curtail wind output to reduce change in net load to 100 MW
$(\Delta L_t - \Delta W_t) \geq 100$	Dispatch contingency reserves to increase supply to cover loss of wind in excess of 100 MW
- $(\Delta L_t - \Delta W_t) \geq 0$	Dispatch down generators in the energy market merit order until supply equals demand
$(\Delta L_t - \Delta W_t) \geq 0$	Dispatch up generators in the energy market merit order until supply equals demand

A flow chart of the simulation program using AESO short term recommendations is shown in Figure 3.3.

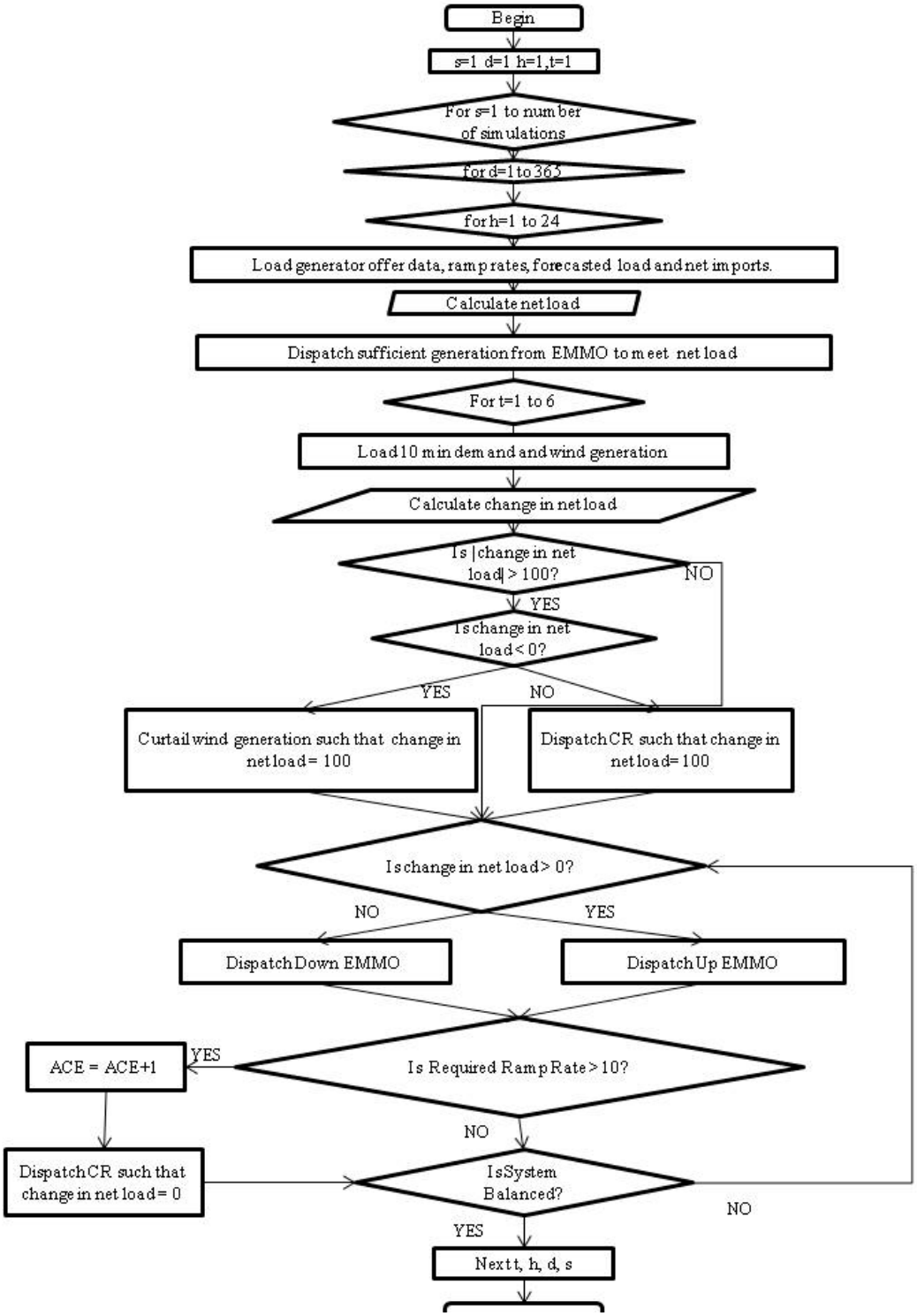

Figure 3.3: Flow chart of simulation with AESO short term recommendations

Net Imports

Net import data are also based on historic Alberta values. The level of net imports is dependent upon the available transfer capacity with the adjacent region. Hourly variation in energy flows occurs along a single interconnection with export and import maximums of 888 MW and 753 MW, respectively, and generally follows the hourly price and profile shown in Figure 3.4

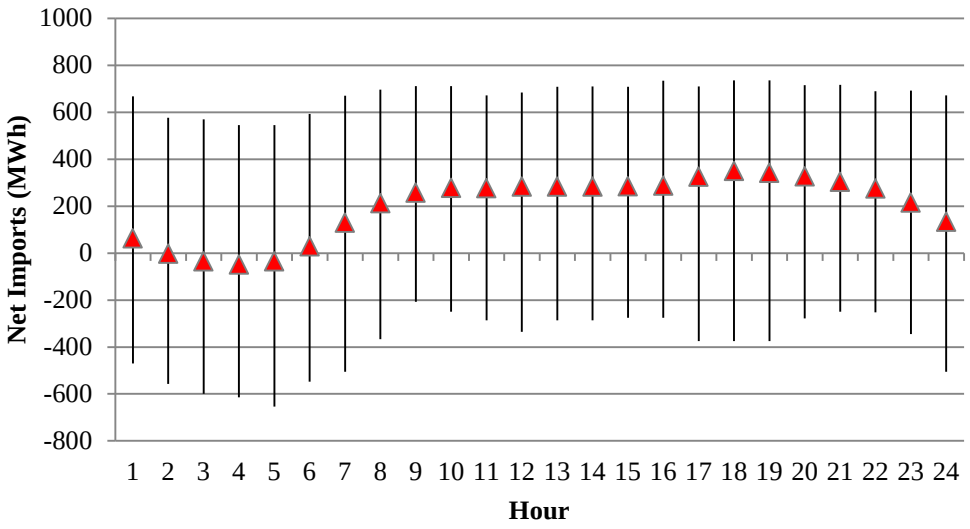

Figure 3.4 Hourly average net import values with minimum and maximums.

Wind

Wind generation is volatile and uncertain. For an accurate portrayal of wind generation we replicate the historical stochasticity. While the Gumbel distribution provides good approximations at higher wind speeds (Sarkar, Singh & Mitra, 2011), the Weibull distribution is the most widely used distribution in wind modeling (see Liu & Xu, 2010; Carta, Ramirez & Velazquez, 2009) and this distribution has been used to specifically model Alberta wind (see AESO, 2005b). The Weibull probability distribution is given as:

$$(x, a, b) = \frac{b}{a}\left(\frac{x}{a}\right)^{b-1} e^{\left(\frac{x}{a}\right)^{b}} \qquad (3.9)$$

where the shape parameter *a* represents how 'peaked' the distribution of wind output is, with a higher value indicated greater volatility of the wind output, and *b* is a scale parameter that represents the degree of dispersion of the samples.

We fit a Weibull distribution to the wind generation data that have been normalized using annual capacity figures. Using the estimated shape and scale parameters, the volatility of wind output is created from the Ornstein-Uhlenbeck mean reverting process.

$$dx = \upsilon(\mu - x)dt + \sigma z \qquad (3.10)$$

where z is drawn from the Weibull distribution described in (3.9); υ is the speed of mean reversion, μ is the long run mean to which the process tends to revert; and σ is a measure of volatility. The mean reverting process is appropriate for this simulation as climate change does not lead to a rising (or falling) wind mean over the short period of time simulated in this study.

The wind power output is from the Alberta Electric System Operator. The file is ten minute metered volumes from all wind producers in Alberta between 2004 and 2010 inclusive; a total of 368,208 data points. The shape and scale parameters were estimated using the 'wblfit' function in MATLAB and yielded shape and scale parameters of 10.22 and 0.2813. The long run mean value (0.276) and speed of mean reversion (0.00005) were estimated from a linear regression on the normalized wind data using the model specification given in (3.10).

After estimating the wind output based on total available capacity, we scale the output using the Alberta average annual wind capacity factor of 32.8 percent. The parameter values are summarized in Table 3.3

Table 3.3: Parameter Values Used in Wind Estimation

Parameter	Value
Weibull shape	10.22
Weibull scale	0.2813
Long Run Mean	0.276
Speed of Reversion	0.00005
Annual Capacity Factor	0.328

Load

The load data are Alberta Interconnected Electric System (AIES) demand from 2010. The provincial demand exhibits a high system load factor with a winter peak load of 10,386 MW and a minimum load value of 6,685 MW. The diurnal load profile reveals lower night time demand and daily peak loads between HE 17 and HE 20.

To simulate the supply stack in 2011 and beyond as accurately as possible, we removed the offer data from the Wabumun 4 coal plant, which was decommissioned in March 2010. We included the two Suncor Firebag cogeneration units (FB3A and FB3B) as baseload units as they are upgrades to the existing baseload SCR1 gas-fired unit that is currently online. Keephills 3, TransAlta's new coal unit, was also added to the EMMO and was assumed to have the same offer strategy and ramp rate as its sister unit, Keephills 2. In addition, we also assume that 200 MW of provincial load is served by behind-the-fence generation in every hour. This has the effect of reducing provincial demand that must be met by EMMO generation.

Operating Reserves

We assume that 253 MW of active and 103 MW of standby contingency reserves are ready for deployment in the short term and fast ramping scenarios but are obviated in the over dispatch protocol. The activation payment remains constant at $16.00/MWh, but the dispatch payment for deployed reserve generators is one-sixth of the Pool price in that hour (i.e., a payment based on the prevailing Pool price for the ten minutes interval the energy is required).

Penalties

ACE events breach reliability standards. The relevant reliability standard for Alberta is BAL-001-AB-0a that requires the system operator keep unscheduled flow less than 60 MW in any ten minute period. Rule 27 of the AUC states that BAL-001-AB-0a violations allow the MSA to impose financial penalties. The value of the penalty depends on the magnitude of the violation. These are outlined in Table 3.4.

Table 3.4: Specified Penalties for Contravention of Reliability Standards

Degree of Violation	Financial Penalty
<10%	$3,000
<10 and >15%	$5,000
<15 and >20%	$7,000
> 20%	$10,000

Source: AUC (2010)

We add to our system costs the financial penalties associated with those ACE events that are greater than ± 60 MW.

3.5 Results

The unit commitment and economic dispatch models are used to simulate the Alberta system with 695 MW,1.1 GW, 1.5GW and 2.5 GW of wind capacity, with load and net imports unchanged in all four cases. For each wind generation level, we ran 1,000 simulations. Both the magnitude and frequency of contingency reserve deployment increases as wind penetration rises, although there is an asymmetry in the dispatch requirements; more contingency reserves are required to manage wind ramp down events than curtailment to manage wind ramp up events, even as the wind power supply increases. Contingency reserve dispatch is not always required during the same intervals for the different wind scenarios indicating that ramp rate constraints are binding. As the level of wind generation changes, it affects the amount of energy required from the EMMO. Thus, as expected the marginal supplier and the corresponding ramp rates are

different under the four wind scenarios. Wind curtailment increases as wind penetration increases; however, in all cases the amount of wind curtailed is less than one percent of total wind generation.

The increase in wind energy reduces the market price of electricity from $29.27/MWh in the base case to $23.35/MWh with 2.5 GW of wind capacity. This lowers the cost of procuring energy to meet demand, the energy payment to contingency reserves and the value of curtailed wind. Although the frequency of contingency reserve dispatches and wind curtailment events increases as wind capacity increases, the total system cost falls due to the price depressing effect of wind generation. The lower market price would likely have the effect of reducing the investment incentives for conventional generation technologies. The same price depressing effect of increased wind penetration on system costs may not be present in regulated electricity markets with fixed prices for energy and/or reserves.

We tabulate total system costs as the sum of energy costs as well as the cost of contingency reserve provision. The value of wasted renewables is assumed to be the opportunity cost of the curtailed wind generation. When wind capacity increases by 260 percent the system costs decline by nearly 21 percent which is the result of the reduction in the market price of electricity. Table 3.5 summarizes the results from the simulations.

Table 3.5 Results from Unit Commitment and Economic Dispatch Simulations

Installed Wind Capacity	695 MW (Base Case)	1.1 GW	1.5 GW	2.5 GW
Average price	$29.27	$27.82	$26.34	$23.35
Times Contingent Reserves Dispatched	827.7	920.4	1,065.5	1,795.7
Cost of contingent reserves ($mil)	$1.18	$1.20	$1.24	$1.42
Total capacity payment ($mil)	$35.46	$35.46	$35.46	$35.46
Number of wind power curtailments	244.1	344.0	514.4	1,390.6
Cost of wind power management ($mil)	0.04	0.04	0.05	0.12
Wind curtailed (MWh)	1,777.05	2,031.95	2,530.90	5,974.15
Total wind generated (GWh)	534.9	846.6	1,154.5	1,924.1
ACE events	6,339.3	6,754.1	7,339.5	9,051.2
Cost of ACE Penalties ($ mil)	$3.642	$4.150	$4.310	$5.042
Energy cost ($mil)	$2,210.69	$2,095.99	$1,978.38	$1,744.10
Total system cost ($mil)	$2,251.02	$2,136.85	$2,019.44	$1,786.15
% Change in Wind		58%	36%	67%
% Change in Costs		-5.07%	-5.49%	-11.55%
% Increase in ACE events		6.54%	8.67%	23.32%
% Change in Wind over Base Case				260%
% Change in Costs over Base Case				-20.7%
% Change in ACE events over Base Case				42.8%

Grid reliability is negatively impacted by higher wind penetrations. Area control errors rise as wind generation increases. We find a 42.8 percent increase in ACE events in the 2.5 GW wind scenario when compared to the base case.

To determine the cost of restoring grid reliability under increasing wind penetrations, we compare the contingency reserves/curtailment protocol to one in which the EMMO is used exclusively to balance supply and demand. We make the same assumptions about wind, load, imports and generator availability and offer strategy as in the previous simulations, but, in this case, contingency reserves and wind curtailment are never used for system balancing. A flow diagram for this procedure, known as over dispatch, is shown in Figure 3.5.

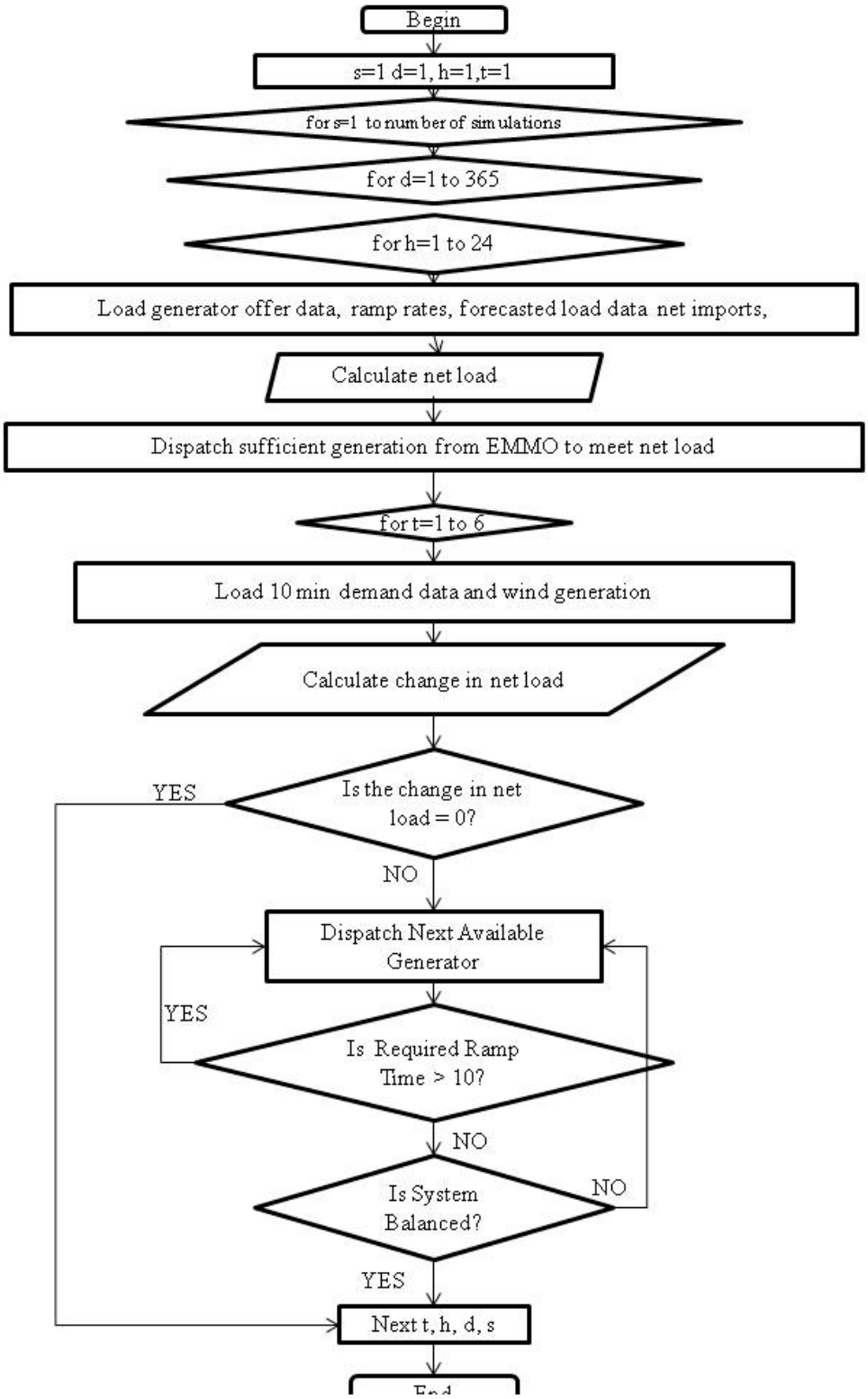

Figure 3.5: Flow chart of simulation program using over dispatch protocol

The over dispatch procedure dictates that, in the case where the next available generator in the merit order is too slow to ramp its output to the required level (either up or down), the next-in-line generator is dispatched to make up the difference even though that faster generator may only be in merit for a short time. In this scenario, we assume that the EMMO does not change; that is, generators pursue the same offer strategies as they would under normal EMMO dispatch procedures. In addition, with over dispatch we exclude the costs of contingency reserve provision as the system operator will not utilize them to mitigate fluctuations in demand and wind generation. We find that applying the over dispatch protocol to the four wind scenarios leads to slightly higher prices for energy. However, total system costs decline as wind penetration increases due to the elimination of contingency reserve payments and the opportunity cost associated with wind curtailment.

The addition of simple cycle gas turbine technology to the merit order could eliminate the need for contingency reserves and over dispatching by providing fast ramping generation to the grid. We simulate the Alberta system again, but this time we assume the existence of sufficient fast-ramping generation.

Using the fast-ramping protocol described in Figure 3.6, we find that even with 2.5 GW of installed wind capacity only 25 MW of peaking capacity would eliminate imbalances 95 percent of the time, while 77 MW of peaking capacity would reduce the need for contingency reserve dispatch 99 percent of the time. Over 772 MW of fast ramping generation would be required to eliminate contingency reserve dispatch. Wind ramp down events are far more prevalent as wind speeds tend to increase slowly and decay quickly. This particular characteristic of wind is problematic as wind ramp down events require a larger amount of contingency reserves and more fast ramping generation than is associated with wind ramp up events.

Figure 3.6: Flow chart for simulation program with fast ramping generation

To determine the cost of adding peaking capacity to the system we use cost specifications for an open cycle gas turbine unit. These are enumerated in Table 3.6.

Table 3.6 Cost Specifications for an Open Cycle Gas Turbine

Parameter	Value
Cost per Installed MW	$744,681
Fuel Cost	$3.03/GJ
Heat Rate	9.65 MW/GJ
Variable O&M	$0.50/MWh

Source: Alberta MSA (2004); Province of Alberta (2010a)

The use of fast ramping capacity with 99 percent mitigation of wind events has a comparable cost with the other protocols, while a 100 percent mitigation strategy with additional peaking generators proves to be far more expensive.

Comparing the costs of managing the system through over dispatch and short-term mitigation methods, the relative merits of the short-term protocols versus over dispatch depends on the total amount of wind capacity; at lower levels of wind penetration, the short-term mitigation protocol is a less expensive mechanism for handling wind ramp events. This may be in part due to a whipsaw effect. Suppose the system controller needs to dispatch off some conventional generators to balance the system because wind generation has increased. Some units with slow ramp rates will take a considerable amount of time to completely adjust their output. If in the interim wind generation decreases, the system controller will need to ramp up generators to offset the wind energy change. This is the ‘whipsaw’ effect where additional generation is dispatched on to offset both the change in wind generation output and the continued

ramping from generators still moving down from a previous dispatch order. However, as wind generation grows, the costs of curtailment and contingency reserve provision are greater than the increase in the Pool price associated with over dispatch. A summary of system costs under the different protocols and wind levels is shown in Figure 3.7.

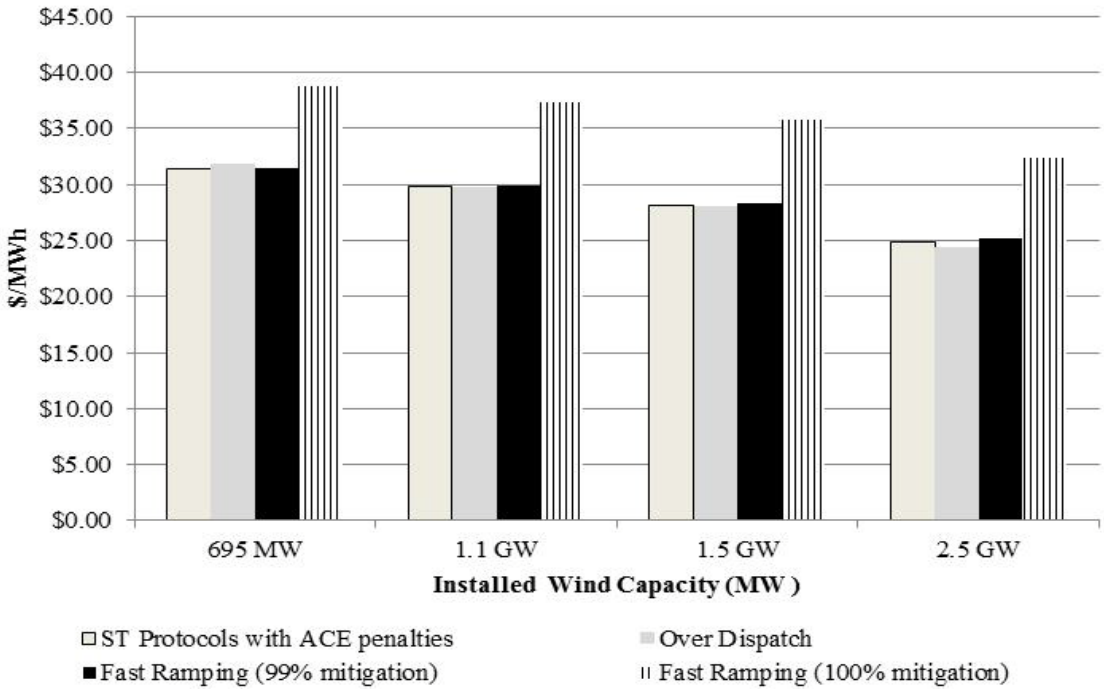

Figure 3.7: Wind integration costs under differing balancing protocols

We run the same simulations but increase demand by two percent in each of the wind scenarios. Increasing demand raises the average cost of electricity while the increases in wind generation tend to depress the price. With 2.5 GW of wind and an additional two percent of demand, the per MWh system cost in the fast ramping scenario with 99% mitigation is almost the same as the base case wind and demand scenario, $31.38 vs. $ 32.25 (see Figure 3.6 and 3.7). Increasing demand by two percent increases the frequency of excess demand situations. We also find that higher demand mitigated some periods of excess supply; however, the frequency of

wind curtailment grew. This is because higher demand exacerbates load ramps in both directions.

Increasing wind generation reduces the number of excess demand situations but does not reduce the number of times that ACE events and wind power management are required. Increasing load mitigates excess supply when wind and load are ramping in the same direction but worsens system imbalances when wind and load are moving in opposite directions, requiring more interventions from the system operator.

When demand is increased, the short term protocol yields the lowest system costs regardless of the wind penetration level. Adding fast ramping generation is the most expensive method for mitigating 100% of the wind events, but, when only 99% of wind ramps are mitigated, much less fast ramping generation is required and the total system costs are almost equal to those under the short term protocol. The system costs with higher demand are shown in Figure 3.8.

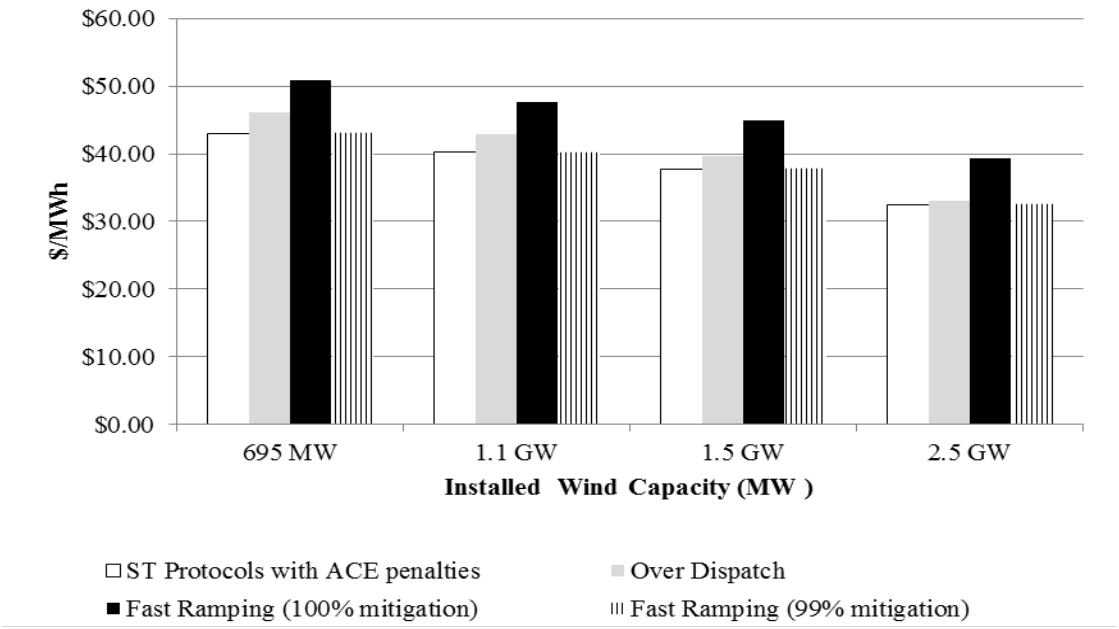

Figure 3.8: Wind integration costs with higher demand

3.6 Conclusions

As additional wind is integrated into deregulated markets, the system balancing costs fall even though both the contingency reserve requirements and wind curtailment increase when wind capacity increases. Wind energy depresses the market price of electricity. The cost of contingency reserves and the value of curtailed wind power are functions of the market price, and, as such, they also decrease as wind penetrations rise. The choice of balancing protocol affects the cost of integrating wind energy into the grid as well as grid reliability. Lower costs, given the current dispatch protocol, are achieved only by increasing wind generation and permitting more security violations thereby decreasing grid reliability.

In simulating the wind capacity levels in each of the dispatch protocols, the EMMO remained the same, providing a typical amount of generation capacity and ramp speed to the system. Varying the amount of available generation might impact the simulation results. For a supply surplus resulting from additional fast ramping generation, more wind ramps would be mitigated and fewer ACE events would be recorded. This scenario was contemplated in the fast-ramping protocol where the amount of extra generation required to eliminate ACE events was estimated.

If additional slower ramping baseload capacity became available, then at higher wind capacity levels, wind ramp down events might lead to more ACE events as the units required to be would not be flexible enough to mirror the wind changes. Greater volumes of unscheduled energy would flow on the Alberta-BC tie line. However since baseload units tend to offer in their energy at zero or near zero prices, energy costs would fall although effect on system costs is uncertain. With the over dispatch approach, a supply surplus resulting from additional baseload capacity might lead to lower energy costs, as the system operator dispatches lower price offers

from close to the bottom end of the EMMO and dispatching faster units only for very short time periods.

Significant generator outages can lead to supply shortfalls as the system operator has little room to move up the EMMO as required. This happened on July 9, 2012, when ten thermal generators accounting for 1400 MW of generating capacity tripped offline during a record summer demand peak. Wind generators provided almost no energy to the grid, contingency reserve volumes fell below required levels, and even with over 500 MW of imported electricity, the system operator was required to shed firm load. Had wind energy been available, the firm load shed events may have been avoided

Changing the manner in which imports are scheduled could provide the energy required to backstop the variability of wind. If net imports were scheduled more frequently, they could be used in the place of contingency reserves to balance the system during wind ramping events. Peaking gas plants may provide the fast ramping capability that the system requires when wind is added to the system, but the lower market price of electricity may not be an adequate incentive for investors to build gas plants.

An efficient solution may be to increase the transmission capacity between Alberta and British Columbia. As will be shown in Chapter 4, British Columbia is in a supply shortage situation but can provide fast responding energy to Alberta when required. Increasing the size of the intertie between the two provinces will allow Alberta to call upon BC energy resources to backstop wind variability while, BC can use Alberta’s excess night time supply to store water for future production.

Chapter 4: Is BC a Net Importer or Exporter?

4.0 Introduction

The Province of British Columbia is committed to becoming energy self-sufficient by 2016, with the proviso that an additional 3,000 MWh of insurance energy also be generated. There is substantial controversy surrounding this goal as it is remarkably difficult to decipher whether BC has been a net importer or exporter in the past due to the distorting effects of revenue-driven energy transactions. BC may import less expensive energy from adjacent regions to save water for future energy production or it may require imports to meet internal load demand. Similarly, it may export energy to high priced regions for revenue and use the accrued financial gains to purchase lower-price energy at other times.

Whether the province can be self-sufficient given the current state of British Columbia's electricity system is the question addressed in this chapter. We create a non-linear programming model of the BC electric system that allows BC to trade electricity with Alberta and the United States. Hydroelectric power production on the two largest rivers (Columbia and Peace) is modeled independently, while remaining hydroelectric production is treated as must run. There is also an option to produce thermal power though provincial policy aims to reduce production using fossil fuels (and nuclear power is ruled out altogether).

Our constrained optimization problem maximizes domestic revenue subject to meeting technical constraints including serving daily domestic load over a one year period. We find that, with no trade and no thermal generation, it is impossible to meet domestic load given the remaining resource configuration. When thermal generation is added, 'normal' system demand can be met, even when trade is not permitted, but reservoir live storage volumes will need to be drawn down to 70 percent of their original starting levels. Allowing imports from Alberta and the

U.S. results in imported energy displacing thermally-generated electricity with the proportion of imports increasing with higher end of year reservoir storage requirements.

While load will likely continue to increase with the population growth, the more pressing question relates to how the provincial government is going to rationalize the self-sufficiency goal with its commitment to liquefied natural gas (LNG) operations. The *BC Jobs Plan* (Province of British Columbia, 2012b) states that BC will have at least one LNG pipeline and terminal in operation by 2015 and three by 2020. When shale gas exploitation is taken into account, the province will require between 2,600 MW and 3,750 MW of new generation capacity. The BC oil and gas industry, the largest revenue sector in BC's economy, will continue to drive both economic growth and electricity demand. In December 2010, BC Hydro forecast a 630 percent electricity load growth for the oil and gas industry over the next five years.

To reduce the gap between actual and required generating capacity, the province could allow for self-generation via natural gas fired units in the province's north east – the gas is available at low cost and, since generation is on-site, transmission issues are all but eliminated. However, the 2010 *Clean Energy Act* requires the province to achieve an 18 percent reduction in provincial CO_2 from 2007 levels, meet 66 percent of new demand through conservation initiatives and use clean or renewable resources to generate electricity. Clearly, British Columbia is at a policy crossroads – it can try to achieve economic growth through resource development or it can aim for energy self-sufficiency, but it likely cannot achieve both.

4.1 Existing BC Electricity Infrastructure

BC Hydro is the single largest entity in BC's electricity sector and the third largest utility in Canada. The government-owned corporation serves 94 percent of the province's population. The corporation's assets include large-scale hydro facilities with storage, run-of-river generating

assets and two thermal generating units. BC Hydro divides its generating system into four regions: Peace, Columbia, Vancouver Island and the lower mainland.

The Peace region includes two major generating facilities on the Peace River: the GM Shrum and Peace Canyon dams. Shrum is comprised of ten generating units that are fed by water flowing from the province's largest storage system, the Williston Reservoir (39,462 million m^3). The Peace River flows through Shrum into Dinosaur reservoir and then through the Peace Canyon dam and generating station. The same amount of water flowing through Shrum also flows through the Peace Canyon turbines making the Peace Canyon station a run-of-river facility.

The Columbia basin includes the Columbia, Kootenay, Pend D'Oreille, Bull, Elk and Spillamacheen rivers. The Columbia River originates in British Columbia and flows through the Pacific Northwest (Washington, Oregon and Idaho). The Columbia River Treaty is an international agreement negotiated between Canada and the U.S. that oversees the development and operation of dams in the upper Columbia River basin. Although the federal government negotiated the Treaty on behalf of Canada, the Canadian benefits and costs are solely attributable to the province of British Columbia.[39] Under the Columbia River Treaty, BC was obligated to construct and operate three dams (Mica, Arrow and Duncan) for the purpose of flood control that benefited the U.S.; thus, BC would need to operate storage in Canada to prevent floods in the U.S. and optimized power production from U.S. dams on the Columbia River. The BC government made a lump sum payment to BC Hydro for the cost of constructing and operating the Treaty dams, while the province receives one-half of the resulting increase in power

[39] The history of the Columbia River Treaty provides a synopsis of the factors leading up to the negotiations, the controversies surrounding the Treaty as well as the costs and benefits associated with it. http://www.empr.gov.bc.ca/EAED/EPB/Documents/History%20ofColumbiaRiverNov139web.pdf

generated in the U.S., which it assigns to BC Hydro's marketing subsidiary, Powerex.

The Libby Coordination Agreement was negotiated in 2000 to resolve a dispute between BC Hydro and the Bonneville Power Authority (BPA)/U.S. Army Corps of Engineers (Corps).[40] The agreement allows the BPA and the Corps to operate the Libby Dam in Montana for fisheries purposes without reducing the power benefits that British Columbia is entitled to under the Columbia River Treaty.

At the top of the Columbia River is the Kinbasket reservoir that stores 14,802 million m^3 of water behind the Mica dam and generating station. The Mica powerhouse has four turbines with a total 1,792 MW of capacity. BC Hydro is in the process of upgrading Mica's generating capacity by installing another two 500 MW turbines that will provide an additional 1,000 MW of capacity. The allocation of Kinbasket reservoir volumes is shown in Table 4.1.

Table 4.1: Kinbasket Reservoir Storage Allocations

Storage Type	Volume (million cubic metres)
British Columbia Storage	616.75
Non-Treaty Storage Agreement (1990)	3,083.75
Non-Treaty Storage Agreement (1984)	2,467.00
Columbia River Treaty Storage	8,634.50

Downstream from Mica is the Revelstoke reservoir, generating station and dam. Revelstoke turbines are powered by water flowing from the Kinbasket reservoir as well as from local inflows. Essentially the Revelstoke power house operates as a massive run-of-river facility.

[40] The Bonneville Power Administration is a U.S. federal energy agency in the Pacific Northwest. BPA markets wholesale electrical power from 31 federal hydro projects in the Columbia River Basin, one non-federal nuclear plant and several other small non-federal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA also operates and maintains about three quarters of the high-voltage transmission in its service territory, which includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

Downstream of Revelstoke is the Hugh Keenleyside Dam that forms the Arrow Lakes Reservoir. BC Hydro and Columbia Power Corporation have recently completed the installation of 185 MW of generating capacity just downstream of the Keenleyside dam.

The Seven Mile generating station is located on the Pend D'Oreille River and has an installed capacity of 594 MW. The Skagit Valley Treaty provided the province with the ability to alter the reservoir level at the Seven Mile dam, but it obligates BC Hydro to deliver the equivalent of 35.4 MW of capacity to the Seattle load centre. BC Hydro is compensated by Seattle for this energy through a series of negotiated payments.

The Columbia basin contains five other smaller generating stations (Aberfeldie, Elko, Spillimacheen, Walter Hardman and Whatshan) operated by BC Hydro. These provide the province with a total of 79 MW of generating capacity.

The largest generating facility in the lower mainland area, and the third largest of BC Hydro's units, is the Bridge River complex. It includes the La Joie Dam and its 25 MW powerhouse, the 480 MW Bridge River generating units and the 24 MW Seton power station. There are an additional nine hydro generating projects in the lower mainland area with a total 542 MW of sustained generating capacity. In addition, the mainland area has two thermal plants, the Prince Rupert and Burrard units with 46 MW and 912.5 MW of capacity, respectively.

Vancouver Island is tied to the lower mainland's transmission infrastructure. The lower mainland provides nearly 80 percent of the Island's electricity needs. The remaining energy requirements are met by 458 MW of local hydroelectric generation including three power generation stations on the Campbell River.

BC Hydro's franchise area is the entire province of British Columbia, but excludes the area serviced by FortisBC (formerly known as West Kootenay Power), which is a regulated

public utility that operates in the province. FortisBC's transmission system connects with BC Hydro to form an integrated provincial electricity grid. FortisBC operates four hydroelectric generating stations on the Kootenay River: Corra Linn, Upper Bonnington, Lower Bonnington and the South Slocan. The four projects provide the province with 235 MW of installed capacity. The Kootenay Canal generation station provides a further 570 MW of capacity. Brilliant generating station, a 125 MW powerhouse, is downstream of the Kootenay Canal project.

A list of BC generating stations, dam names and heights, reservoir names and sizes is provided in Table 4.2. Nelson Hydro operates generation, transmission and distribution facilities for the City of Nelson. The Cities of New Westminster, Grand Forks, Kelowna and Penticton, as well as Summerland Power and Hemlock Valley Utilities, distribute power to their customers after purchasing electricity from BC Hydro or FortisBC.

In addition to publicly owned generation facilities, independent power projects (IPP) are being built and operated by private firms. Teck is an international mining corporation operating in British Columbia; it owns a two-thirds interest in Waneta Dam and 15 km of transmission line connecting its BC operations to the U.S.[41] Rio Tinto Alcan owns the Kemano hydroelectric facility and the accompanying transmission assets that enable it to connect to BC Hydro's grid. Nonetheless, BC Hydro manages the largest share of the provincial capacity, although IPP generation is growing in size and importance in the BC generating portfolio. Table 4.3 provides a list of IPP projects that are currently generating energy for BC Hydro. The projects were constructed and the energy procured under various power calls issued by BC Hydro.

[41] As of March 5, 2010, Teck sold one-third of an interest in Waneta dam to BC Hydro for $850 million.

Table 4.2: BC Hydro and FortisBC Generating Units

Project Name	Area	Owner/Operator	Capacity	Dam Height	Reservoir Name	Reservoir Size
Aberfeldie	Columbia	BC Hydro	5 MW	32 m	Aberfeldie Headpond	Run of River
Alouette	Lower Mainland	BC Hydro	9 MW	21 m	Alouette Lake	1600 ha, 155 mil m^3
Ash River	Island	BC Hydro	27 MW	19 m	Elsie Lake	75 ha, 77 mil m^3
Bridge River	Lower Mainland	BC Hydro	480 MW	60 m	Carpenter	4800 ha, 928 mil m^3
Brilliant	Columbia	FortisBC	125 MW	42.6 m		
Buntzen/Coquitlam	Lower Mainland	BC Hydro	72.8 MW	16.5m/30m	Buntzen Lake/Coquitlam Lake	185 ha, 202 mil m^3
Burrard Thermal	Lower Mainland	BC Hydro	912.5 MW	n/a	n/a	n/a
Cheakamus	Lower Mainland	BC Hydro	157 MW	29 m	Daisy Lake	4600 ha, 46 mil m^3
Clowhom	Lower Mainland	BC Hydro	33 MW	22 m	Clowhom Lake	800 ha, 45 mil m^3
Corra Linn	Columbia	FortisBC	49 MW	16 m	Kootenay Lake	
Duncan	Columbia	BC Hydro	None	38.7 m	Duncan Lake	1727 mil m^3
Elko	Columbia	BC Hydro	12 MW	16 m	Elk Headpond	None
Falls River	Lower Mainland	BC Hydro	7 MW	13 m	Big Falls Headpond	24 mil m^3
GM Shrum	Peace	BC Hydro	2730 MW	183 m	Williston	177000 ha, 39462 mil m^3
Hugh Keenleyside	Columbia	BC Hydro	185 MW	52 m	Arrow Lakes Reservoir	51600 ha, 8770 mil m^3
John Hart	Island	BC Hydro	126 MW	34 m	John Hart Reservoir	250 ha, 3.3 mil m^3
Jordan River	Island	BC Hydro	170 MW	27.4 m (Elliott), 39.9 m (Jordan), 19m (Bear	Elliot, diversion and Bear Creek	16 ha (Elliot), 168 ha (Diversion), 75 ha (Bear
Keogh Thermal	Island	BC Hydro	44 MW	na	na	Na
Kootenay Canal	Columbia	FortisBC and Teck	570 MW	38m	Kootenay Canal Headpond	Licensed to FortisBC and Teck
Ladore	Island	BC Hydro	47 MW	37.5 m	Lower Campbell Lake	3700 ha, 316 mil m^3

Project Name	Area	Owner/Operator	Capacity	Dam Height	Reservoir Name	Reservoir Size
La Joie	Lower Mainland	BC Hydro	25 MW	87 m	Downton	2400 ha, 722 mil m^3
Lower Bonnington	Columbia	FortisBC	66 MW			
Mica	Columbia	BC Hydro	1792 MW	244 m	Kinbasket	42500 ha, 14800 mil m^3
Peace Canyon	Peace	BC Hydro	700 MW	61 m	Dinosaur	890 ha, 24 mil m^3
Prince Rupert Thermal	Lower Mainland	BC Hydro	46 MW	n/a	n/a	n/a
Puntledge	Island	BC Hydro	24 MW	10.7 m (Comox), 5.5 m (Puntledge)	Comox Lake	3000 ha (Comox), 106 mil m^3
Revelstoke	Columbia	BC Hydro	1980 MW	175 m	Revelstoke	11530 ha, 1850 mil m^3
Ruskin	Lower Mainland	BC Hydro	105 MW	59.4 m	Hayward Lake	300 ha, 24 mil m^3
Seton	Lower Mainland	BC Hydro	48 MW	14.4 m	Seton Lake	2460 ha, 9 mil m^3
Seven Mile	Columbia	BC Hydro	848 MW	80m	Seven Mile	410 ha daily pondage
Shuswap	Lower Mainland	BC Hydro	6 MW	30 m (Wilsey), 13.4	Sugar Lake	2100 ha, 148 mil m^3
South Slocan	Columbia	FortisBC	54 MW			
Spillimacheen	Columbia	BC Hydro	4 MW	14.5 m	n/a	n/a
Stave Falls	Lower Mainland	BC Hydro	90 MW	26 m	Stave Lake	6200 ha, 365 mil m^3
Strathcona	Island	BC Hydro	64 MW	53 m (Strathcona), 9.8	Upper Campbell Lake, Buttle Lake	6680 ha combined, 823 mil m^3
Upper Bonnington	Columbia	FortisBC	66 MW			
Wahleach	Lower Mainland	BC Hydro	63 MW	21 m	Jones Lake	491 ha, 66 mil m^3
Walter Hardman	Columbia	BC Hydro	8 MW	19m (Coursier), 12 m (Walter Hardman	Coursier Lake	200 ha29 mil m^3
Waneta Dam	Columbia	BC Hydro and FortisBC	490 MW	76 m		1/3 interest owned by BCH
Whatshan	Columbia	BC Hydro	54 MW	12 m	Whatshan Lake	1700 ha, 122 mil m^3

Source: BC Hydro (2000)

Table 4.3: IPP Generation procured for and by BC Hydro (as of April, 2011)

Project Name	IPP/Seller	Type	Capacity (MW)	Energy (GWh)
Coats IPP	Crofter's Gleann Enterprises	Run of River Hydro	<0.5	1
Mamquam Hydro	Coastal Rivers Power LP	Run of River Hydro	58	250
McMahon Generating	McMahon Cogeneration Plant JV	Gas Fired Thermal	105	840
NWE Williams Lake WW	NW Energy (Williams Lake) LP	Biomass	68	545
Akolkolex	Canadian Hydro Developers, Inc.	Run of River Hydro	8	50
Boston Bar Hydro (Scuzzy Creek)	Boston Bar Limited Partnership	Run of River Hydro	6	38
Brown Lake Hydro	CP Renewable Energy (B.C.) LP	Run of River Hydro	7	57
Doran Taylor	Doran Taylor Hydro (JV partnership)	Run of River Hydro	6	23
East Twin Creek Hydro	Valemount Hydro LP	Run of River Hydro	2	6
McDonald Ranch	McDonald Ranch & Timber Co. Ltd.	Run of River Hydro	<0.5	<0.5
Morehead Creek	Morehead Valley Hydro Inc.	Run of River Hydro	<0.5	<0.5
Robson Valley (Ptarmigan Creek - RBV)	Robson Valley Power Corp	Run of River Hydro	4	26
Seaton Creek Hydro (Homestead)	Homestead Hydro Systems	Run of River Hydro	<0.5	1
Sechelt Creek (Salmon Inlet)	MPT Hydro LP	Run of River Hydro	17	68
Soo River	Soo River Hydro	Run of River Hydro	13	65
Walden North	Walden Power Partnership	Run of River Hydro	18	54
Island Generation	V.I. Power Limited Partnership	Gas Fired Thermal	275	2300
Arrow Lakes Hydro	Arrow Lakes Power Corporation	Storage Hydro	185	767
Hartland Landfill Gas Utilization	Maxim Power Corp.	Biogas	2	15
Hystad Creek Hydro	Valemount Hydro LP	Run of River Hydro	6	20
Miller Creek Power	CP Renewable Energy (B.C.) LP	Run of River Hydro	30	118
Brandywine Creek Small Hydro	Rockford Energy Corp.	Run of River Hydro	8	34
Eagle Lake C2 Micro Hydro	Pacific Cascade Hydro Inc.	Run of River Hydro	<0.5	1
Furry Creek	Furry Creek Power Ltd.	Run of River Hydro	10	40
Hauer Creek (aka Tete)	Hauer Creek Power Inc.	Run of River Hydro	2	13
Marion 3 Creek	Marion Creek Hydro Inc.	Run of River Hydro	5	18
McNair Creek Hydro	McNair Creek Hydro Limited Partnership	Run of River Hydro	10	38
Mears Creek	Synex Energy Resources Ltd.	Run of River Hydro	4	20
Raging River 1 Small Hydro	Raging River Power & Mining Inc.	Storage Hydro	2	13
South Sutton Creek	South Sutton Creek Hydro Inc.	Run of River Hydro	5	26
Vancouver Landfill Gas Utilization - Ph 1	Maxim Power (BC) Inc.	Biogas	6	40
Pingston Creek	Pingston Creek Hydro Joint Venture	Run of River Hydro	45	193
Ocean Falls	Boarlex Ocean Falls LP	Run of River Hydro	15	12
Queen Charlotte Power Corporation	Coastal Rivers Power LP	Biogas	2	15
Hluey Lake Project (SNP)	MPT Hydro LP	Run of River Hydro	3	5
Rutherford Creek Hydro Project	Rutherford Creek Power Ltd.	Run of River Hydro	50	172
Upper Mamquam Hydro	Canadian Hydro Developers	Run of River	25	108

Project Name	IPP/Seller	Type	Capacity (MW)	Energy (GWh)
South Sutton Creek	South Sutton Creek Hydro	Run of River	5	26
SEEGEN (Burnaby Incinerator)	Covanta Burnaby Renewable Energy Inc.	Municipal Solid Waste	22	131
Ashlu Creek Water Power	Ashlu Creek Investments, Inc.	Run of River Hydro	50	269
Brilliant Expansion 1	Brillian Expansion Power Corporation	Storage Hydro	120	203
China Creek Small Hydroelectric	Upnit Power LP	Run of River Hydro	6	25
South Cranberry Creek	Advanced Energy Systems 1 LP	Run of River Hydro	9	26
Vancouver Landfill Gas Utilization - Ph 2	Maxim Power (BC) Inc.	Biogas	2	15
Zaballos Lake	Zaballos Lake Hydro LP	Storage Hydro	22	93
150 Mile House ERG	EnPower Green Energy Generation LP	Energy Recovery Generation	6	34
Bear Mountain Wind Park	Bear Mountain Wind LP	Wind	102	197
Bone Creek Hydro	Valisa Energy Inc.	Run of River Hydro	20	81
Brilliant Expansion 2	Brillian Expansion Power Corporation	Storage Hydro	< 0.5	226
East Toba and Montrose	Toba Montrose General Partnership	Run of River Hydro	196	715
Eldorado Reservoir	District of Lake Country	Storage Hydro	1	4
Kwalso Energy	Harrison Hydro LP	Run of River Hydro	90	384
Lower Clowhom	Clowhom Power LP	Run of River Hydro	11	48
Savona ERG	EnPower Green Energy Generation LP	Energy Recovery Generation	6	41
Tyson Creek Hydro	Tyson Creek Hydro Corp	Storage Hydro	9	53
Upper Clowhom	Clowhom Power LP	Run of River Hydro	11	48
Upper Stave Energy	Harrison Hydro LP	Run of River Hydro	60	264
Alcan Long Term Electricity Purchase	Rio Tinto Alcan Inc.	Storage Hydro	896	1945
Celgar Green Energy	Zellstoff Celgar LP	Biomass	78	242
PGP Bio Energy Project	Canfor Pulp Ltd. Partnership	Biomass	60	85
Canoe Creek Hydro	Canoe Creek Hydro Company	Run of River Hydro	6	16
Cedar Road LFG Inc.	Cedar Road LFG Inc.	Run of River Hydro	1	11
Cypress Creek	Synex Energy Resources Ltd.	Run of River Hydro	3	12
Fitzsimmons Creek	Fitzsimmons Creek Hydro LP	Run of River Hydro	8	36
Armstrong Wood Waste Co-Gen (RVG)	Tolko Industries	Biomass	20	163
Dokie Wind	Dokie General Partnership	Wind	144	341
Skookumchuk Power Project	Tembec	Biomass	51	206
Pine Creek	XEITL LP	Run of River Hydro	2	5
Howe Sound Green Energy	Howe Sound Pulp and Paper Corporation	Biomass	112	400
Kamloops Green Energy	Domtar	Biomass	76	288
LP Golden Biomass	Louisiana-Pacific Canada Inc.	Biomass	8	4
South Cranberry Creek 2	Advanced Energy Systems 1 LP	Run of River Hydro	<0.5	6

Source: BC Hydro (2011a)

The projects in development as of October 2011 under various BC Hydro Power Calls are enumerated in Table 4.4. Not all of these projects will be completed however, and BC Hydro assumes a 30 percent attrition rate for IPP projects under development (BC Hydro, 2008).

British Columbia is able to flow energy to adjacent markets due to interconnections with Alberta and the United States. BC's grid is linked to Alberta via two 138 kV lines and one 500 kV line. The operational transfer capability (OTC) represents the maximum amount of electricity that can flow along the transmission interties. For BC, the OTC to the U.S. is 3,150 MW from north to south and 2,000 MW from south to north. With respect to the transmission capacity between Alberta and BC, the east to west capacity is 1,000 MW while the west to east OTC is 1,200 MW; however, in 2010, operating limitations within Alberta restricted actual transfer capacity to a maximum 735 MW east-to-west and 600 MW west-to-east.

Table 4.4: IPP Projects Currently Under Development

Project Name	Generation Type	Capacity (MW)	Expected Annual Energy Output (GWh)
Mkwa'alts Creek	Run of River Hydro	45	154
Cranberry Creek Power	Run of River Hydro	3	11
Kwoiek Creek Hydroelectric	Run of River Hydro	50	147
Barr Creek	Wind	4	15
Corrigan Creek	Run of River Hydro	7	19
Sakwi Creek Run of River	Run of River Hydro	5	21
Maroon Creek Hydro	Run of River Hydro	5	25
Clint Creek Hydro	Run of River Hydro	6	27
Raging River 2	Run of River Hydro	8	30
Log Creek Hydroelecric	Run of River Hydro	10	38
Kookipi Creek Hydroelectric	Run of River Hydro	10	39
Victoria Lake Hydroelectric	Run of River Hydro	10	39
Fries Creek	Run of River Hydro	9	41
Gold River Power	Municipal Solid Waste	90	745
PGWE2008	Biomass	8	70
Lower Bear Hydro	Run of River Hydro	10	46
Upper Bear Hydro	Run of River Hydro	10	73
Long Lake Hydro	Storage Hydro	31	139
Beaver River (Ventego, Cupola)	Run of River Hydro	44	140
Tumbler Ridge Wind	Wind	47	153
Bullmoose Wind Project	Wind	60	158
Big Silver - Shovel Creek	Run of River Hydro	37	159
Kokish River	Run of River Hydro	45	186
Bremner -Trio	Run of River Hydro	45	204
Wildmare Wind	Wind	77	224
Ramonas - CC Creek - Chickwat	Run of River Hydro	45	225
Upper Lillooet River	Run of River Hydro	74	270
Cape Scott	Wind	99	288
Upper Toba Valley	Run of River Hydro	124	315
Castle Creek	Run of River Hydro	6	35
Meikle Wind	Wind	117	362
Quality Wind	Wind	142	459
Box Canyon	Run of River Hydro	15	54
North Creek Hydroelectric	Run of River Hydro	16	60
Crowsnest Pass	Energy Recovery Generation	11	65
Northwest Stave River	Run of River Hydro	18	65
Culliton Creek	Run of River Hydro	15	74
Jamie Creek	Run of River Hydro	19	74
Dasque - Middle	Run of River Hydro	20	81
Tretheway Creek	Run of River Hydro	21	81
Boulder Creek	Run of River Hydro	23	86
Skookum Power	Run of River Hydro	25	95
Catalyst Paper	Biomass	38	151
Cariboo Pulp and Paper	Biomass	61	172
Waneta Expansion	Run of River Hydro	335	630
Forrest Kerr Hydroelectric	Run of River Hydro	195	942
Greater Nanaimo PCC Cogeneration	Biogas	0.5	2
Conifex Green Energy	Biomass	36	209

Source: BC Hydro (2011b)

Generating Capacity vs. Power Production

To determine whether BC is a net importer or net exporter of electricity, it is important to distinguish between generated power (energy) and generating capacity. Generating capacity refers to the full-load continuous rating of a generator, also known as the nameplate rating or maximum continuous rating (MCR). Fossil fuel-fired generators are able to provide power consistently near their MCR because of a constant and unvarying fuel supply. The electricity that is generated from intermittent fuel source technologies depends on the availability of the fuel source, whether water, wind or sun. Hydroelectric units are reliant on sufficient water inflows and, even where they are supported by reservoir infrastructure, adequate head height, which depends on reservoir levels (also known as elevations). Treaty and in-stream environmental considerations, such as flood control and fish habitat, affect the owner's ability independently to manage these elevations. Thus, the power output from hydroelectric generators may vary significantly from their rated capacity in any given hour, day, month, season and/or year.

Independent power projects (IPPs) with a variable fuel source are likely to have an even greater discrepancy between capacity values and energy output. Run-of-river hydroelectric generation uses only the actual flow of water to generate electricity; there is no associated water storage capability. Wind energy output will also be less than its installed capacity value, as power is produced only during periods of sufficient wind. If the wind is too strong, wind turbines are required to shut down due to safety concerns, while too little wind will not enable power production at anything near a turbine's generating capacity (or may even result in zero output).

Capacity vs. Peak Load

When the BC electricity system was built, the additional cost of adding turbines to large-scale dams was relatively small; it was rather easy to add capacity. Even though not all dams constructed under the Columbia River Treaty included power generators (many of which were

added later), British Columbia never the less purposefully overbuilt the electricity system's capacity relative to immediate and foreseeable demands. Excess capacity continues to exist even today. As of 2012, excluding the Burrard thermal plant, we estimate that the province of British Columbia has approximately 14,810 MW of generating capacity.[42] Total generating capacity is comprised of 10,277 MW of BC Hydro capacity, 850 MW of FortisBC managed capacity and 2,313 MW of existing independent project projects (IPP). Further, Rio Tinto Alcan has allocated 200 MW of capacity at its Kemano facility to the province. In addition, British Columbia is allocated the Canadian Entitlement (CE) power from the Columbia River Treaty, which provides capacity equivalent to 1,170 MW of installed generation. The composition of currently available capacity is shown in Figure 4.1.

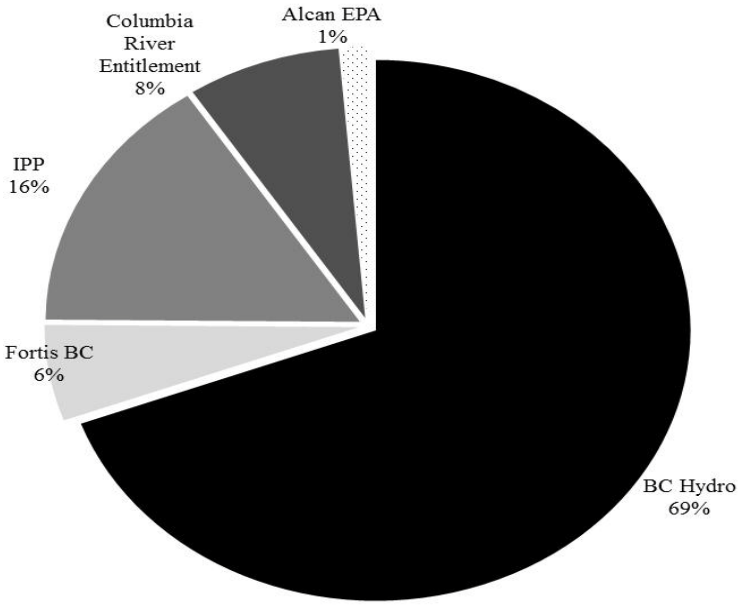

Figure 4.1: Ownership of BC's 13,250 MW of generating capacity

[42] The Burrard natural gas plant is a peaking plant that was used at times when (peak) demand and export commitments happen to exceed immediate generation. On October 28, 2009, the BC Ministry of Energy and Mines announced that the Burrard plant would be used to provide electricity to the grid only in cases of generation and transmission outages or to provide reactive power to maintain voltage requirements within system tolerance limits.

In the future, BC Hydro is planning to upgrade the Mica dam site with two turbines that will provide an additional 1,000 MW of capacity, while a 500 MW upgrade to the Revelstoke dam is currently under construction. Provincial capacity will be further supplemented when projects from BC Hydro's Clean Power Call become operational. BC Hydro anticipates approximately 1,116 MW of renewable energy projects will be constructed from the selected proponents. In addition, the province is moving ahead with the construction of the proposed Site C hydro facility on the Peace River, which will provide an additional 1,098 MW of capacity to the province. The expected completion date for the project is 2020.

Disregarding LNG and projected oil and gas development, BC's total generating capacity is greater than peak load as estimated by BC Hydro in its 2008 *Long Term Acquisition Plan* (LTAP) and by FortisBC in its 2009 *Resource Plan*. Since these utilities serve 100 percent of the provincial load, aggregating the two demand forecasts provides the total forecasted electricity demand between 2010 and 2027.

Peak load is the demand-side equivalent of installed capacity. It is defined as the maximum instantaneous load or the maximum average load over a designed interval of time (usually no longer than one hour). In the BC Hydro and FortisBC forecasts, the peak load is the maximum load in any one hour within a given year. Without the development of LNG facilities and mining projects, provincial peak demand is forecast to exceed the province's existing generating capacity of 14,810 MW no earlier than in 2019.

This excess capacity argument is corroborated by data on BC Hydro's System Capacity Supply (BC Hydro 2008a, Table 6-12). BC Hydro assumes there will be a reduction in load as a result of its demand-side management programs. Then, under normal load conditions and taking into account supply reserves, BC Hydro does not anticipate a shortage in capacity until 2028. In

its LTAP, BC Hydro subtracts 14 percent from its available generating capacity and an additional 400 MW for reserve purposes. These reserves are maintained to ensure that the system is able to meet domestic demand in all but the most extreme circumstance; the industry standard is to maintain supply so that a loss of load event will occur only once in 10 years.

The LTAP states that total BC Hydro capacity is comprised of 9,700 MW of heritage hydroelectric generation, although available hydro capacity appears to be closer to 10,277 MW. This discrepancy requires further investigation as it is beyond the present scope of this research. The second line item provides generating capacity figures for Heritage Thermal assets and Market Purchases. The *Long Term Acquisition Plan* was filed prior to the government's announcement reducing Burrard's availability, and so the figures include the capacity of the Burrard thermal plant. The total capacity associated with thermal and market purchases was 950 MW, of which Burrard plant capacity accounts for 912.5 MW; thus intended market purchases were projected to be quite small. Interestingly, the System Capacity Supply includes 656 MW of electricity purchase agreements, excluding its contract with Alcan. However, "as of April 1, 2010, BC Hydro has 63 Electricity Purchase Agreements (EPAs) with IPPs whose projects are currently delivering power to BC Hydro. These projects represent 10,343 GWh of annual supply and 2,629 MW of capacity" (BC Hydro 2010a, p. 1), indicating a capacity factor of 44.9 percent. Removing Alcan's capacity from BC Hydro's list of EPAs reduces total available IPP capacity to 1,733 MW, a figure substantially greater than the 656 MW enumerated in the System Capacity Supply table (BC Hydro 2008a, Table 6-14).

Capacity from Site C and the Mica upgrades appear as line items under proposed future supply, but there is zero capacity associated with these facilities through 2028. The Canadian Entitlement from the Columbia River Treaty is treated as "additional supply potential" but with

zero associated MW of capacity after 2010. There appears to be a discrepancy between the amount of capacity available and the amount enumerated by BC Hydro (2008a).

BC Hydro (2008a, Table 6-15) also details its electricity flows over a fiscal year. As with System Capacity Supply, the supply of electricity appears to have the same types of distortion: underestimating the electricity from heritage hydro assets, existing purchase agreements (EPAs) and a failure to include the potential future electricity to be generated from the Columbia Entitlement, Site C or the Mica upgrades.

Available Electricity

Since capacity exceeds load, theoretically and under ideal conditions, British Columbia would appear able to meet all its electricity needs domestically. However, capacity and demand (load) do not tell the whole story. A turbine's capacity is the amount of power that can be generated or produced under normal conditions. Unlike thermal generating facilities where the fuel source is constant, a hydroelectric facility's output depends on water flows (as noted earlier). Hydropower is generated when flowing/falling water flows propels the turbine blades. The amount of power that can be generated from a hydroelectric unit depends on the head height – the water stored in the reservoir (elevation) and, thus, water inflows from rainfall or snowpack runoff. In periods of drought, or at times when storage conditions are unfavourable, water volume may be lower than that required to operate the turbines at their capacity. Conversely, during periods of sufficient precipitation, water volumes must be managed for flood control (i.e., water held back when it may be needed to generation power) and power generation while satisfying in-stream uses. Environmental constraints could result in 'spilling' – releasing water when generation is not needed.

4.2 British Columbia's Electricity Trading

Information on power flows is collected by Statistics Canada (CANSIM) and disseminated by the National Energy Board (NEB) and BC Stats. The CANSIM data are collected via a monthly survey from provincial electricity generators. Survey respondents must provide information on the quantity of electricity generated, the primary fuel source used in its generation, and gross receipts and deliveries of electricity to other provinces. These are aggregated across respondents and available in CANSIM tables 1270001 and 1270003. The CANSIM, NEB and BC Stats data are identical, but breakdown the information differently. For example, CANSIM provides monthly data and has information on the types of delivery (firm and non-firm) as well as the source or delivery point (U.S., other provinces). From the NEB data, it is possible to determine the amount of power imported and exported for non-revenue purposes (i.e., 'Treaty power' and ancillary services/losses, etc.). BC Stats data are a summary of CANSIM figures with positive (negative) values representing net exports (imports).

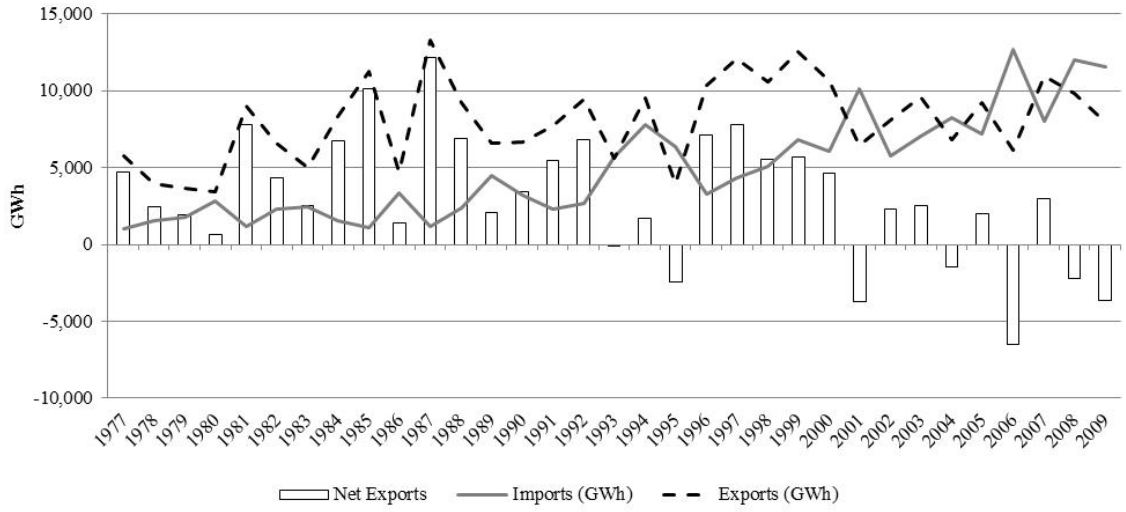

Figure 4.2: Net exports, total exports and total imports, 1978-2008

In Figure 4.2, we track BC electricity exports, imports and net exports (exports minus

imports) between 1978 and 2008 using monthly Statistics Canada data. The data are aggregated over the province's fiscal year, April 1 to March 31, to provide consistency with BC Hydro documents. The grey bars indicate net exports. Prior to 1993, BC was exclusively a net exporter. Beginning in 1993, BC varied its position from being a net exporter to net importer and back again on various occasions. In essence, British Columbia was exclusively a net exporter of electricity prior to 1993 – the amount of energy leaving the province consistently exceeded the amount entering. Between 1993 and 2008, BC was both a net importer and a net exporter of electricity. Over the period 2000 to 2009 BC was a net importer in five years (2001, 2004, 2005 2008 and 2009) and a net exporter in four years (2000, 2002, 2003 and 2007).

The net export data from Statistics Canada do not agree with the dates and volumes of net exports from BC Hydro's 2006 *Integrated Energy Plan* (IEP). The IEP states that BC Hydro was a net importer in five of the eight years – 2001, 2002, 2003, 2004 and 2005. The discrepancy around the net export question may be because BC Hydro generates a large portion, but not all, of the province's electricity. It could also be related to the accounting mechanism used to record BC Hydro sales to Powerex. As the electricity marketing subsidiary of BC Hydro, Powerex is responsible for marketing BC Hydro's surplus electricity, including the Canadian Entitlement energy from the Columbia River Treaty. Clearly, it is important to distinguish between the net position of BC Hydro, its subsidiaries and the province as a whole.

The Statistics Canada data are the aggregation of provincial survey results. Raw data on hourly power flows, both inter-provincial and international, are provided by British Columbia Transmission Corporation (BCTC, 2010a) and are shown in Figure 4.3 where the darker line shows aggregated monthly flows between Alberta and BC, while the lighter line represents the aggregated monthly flows along the BC-U.S. intertie. The aggregation masks the true volatility

of the power flows. Trends in the intertie data appear to be consistent with information from Statistics Canada and the NEB. BC was net exporter to Alberta and a net importer from the U.S. in 2008 and 2009, but a net exporter to both jurisdictions in 2007. The explanation for this import and export pattern is likely the result of variation in electricity prices in the adjacent markets and revenue maximizing behaviour on the part of British Columbia, as discussed in the next section. However, it is important to note that discrepancies of the sort discussed above may be a function of how BC Hydro and Powerex account for internal transfers and forward trades.

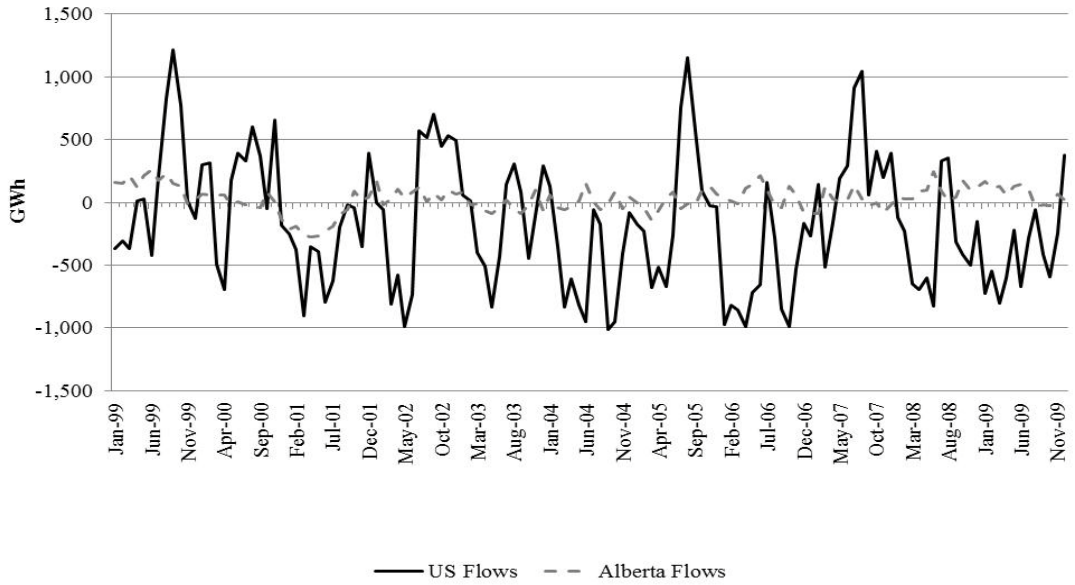

Figure 4.3: BC imports and exports of electricity

Net Revenues Associated with Exports and Imports

Alberta is likely the electricity industry's bellwether because the absence of regulation allows the market to act unencumbered. While experiencing fully deregulated wholesale energy markets, Alberta has already integrated over 860 MW of wind energy. The effect of this high wind penetration has been to increase the volatility in market prices. As the market price in

Alberta rises, there is greater value to generating electricity (i.e., installing added capacity), including, importantly, renewable capacity.

Given the desire across North America to reduce CO_2 emissions associated with fossil fuel generation of power, particularly generation from coal, there may be increased opportunities for lucrative exports of clean energy to the U.S. Renewable energy policies in many U.S. states have left some jurisdictions supply constrained, resulting in higher prices. The restrictive conditions on the types of energy these states can import may benefit British Columbia because of its predominantly hydroelectric generation portfolio. As a result of its excess capacity, BC is able to take advantage of higher prices in adjacent markets. Fundamentally, BC must decide at which price point it is economically beneficial to produce power for export as opposed to purchasing power to meet domestic demand, or meeting domestic demand from domestic generation. As prices rise in adjacent markets, BC will need to increase its capacity to leverage its naturally long position.

British Columbia exports and imports energy at prevailing market prices. In Alberta, prices are determined by the Alberta Electric System Operator (AESO) on an hourly basis (see Chapter 2), while the U.S. price of electricity available to BC is determined at the Mid-Columbia (Mid-C) trading hub. All excess energy supply from BC Hydro is sold to Powerex under the Transfer Price Agreement, which guarantees BC Hydro the Mid-C price. The Mid-C price is a weighted average price based on day-ahead bilateral trades. Electricity markets in California, as well as trading hubs at Palo Verde, Meade and Four Corners, will affect the market price in Mid-C as electricity flows to the highest priced region, although transmission constraints prevent electricity prices from equalizing throughout the Western Electricity Coordinating Council (WECC) region. Transmission constraints characterize the Western provinces and states. As

shown in Figure 4.4, differences in the average electricity prices between Alberta and Mid-C provide evidence of this discontinuity in electricity flows.

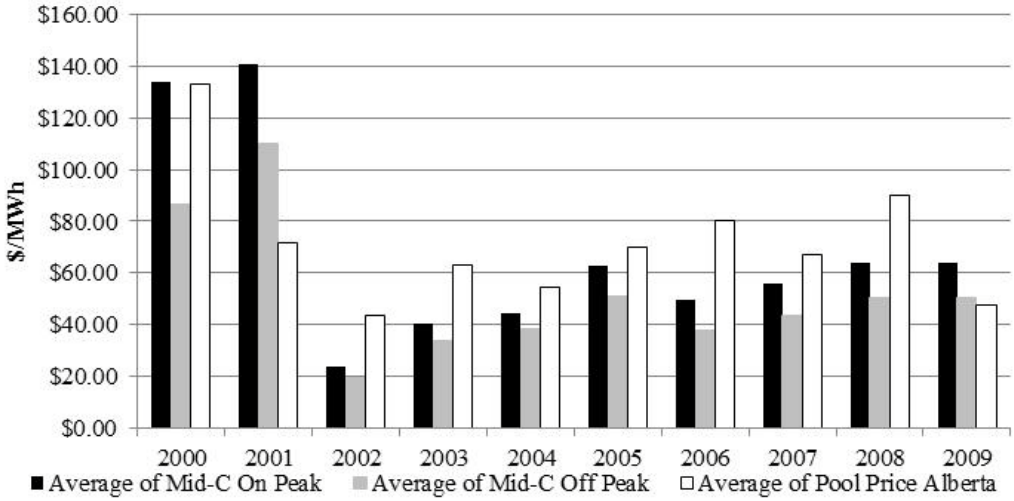

Figure 4.4: Average electricity prices in Alberta and Mid-Columbia

There are times when it is prudent for BC to purchase electricity from its neighbours in Alberta and the Pacific Northwest; the province may also choose to export energy to those areas when it is lucrative to do so. The price point that triggers imports and exports depends on the relative internal cost of producing electricity. According to the 2006 BC Hydro *Integrated Energy Plan* (IEP), from 2001 to 2005, BC Hydro was a net importer of electricity. This was because **"**market purchases were economic to serve domestic requirements when compared to greater use of Burrard or greater drawdown of major reservoir**"** (BC Hydro, 2006, p. 3-7).

The increased use of imports was not due to an inability to meet load with domestic assets but was prudent from a financial perspective – import prices must have been low relative to the cost of domestic generation. Plotting Alberta power prices with BC electricity flows along the AB/BC tie line shows a strong correlation between the two series, providing some evidence that BC acts as a revenue maximizing entity (Figure 4.5). Positive values represent net exports

from British Columbia; negative values are BC imports from Alberta.

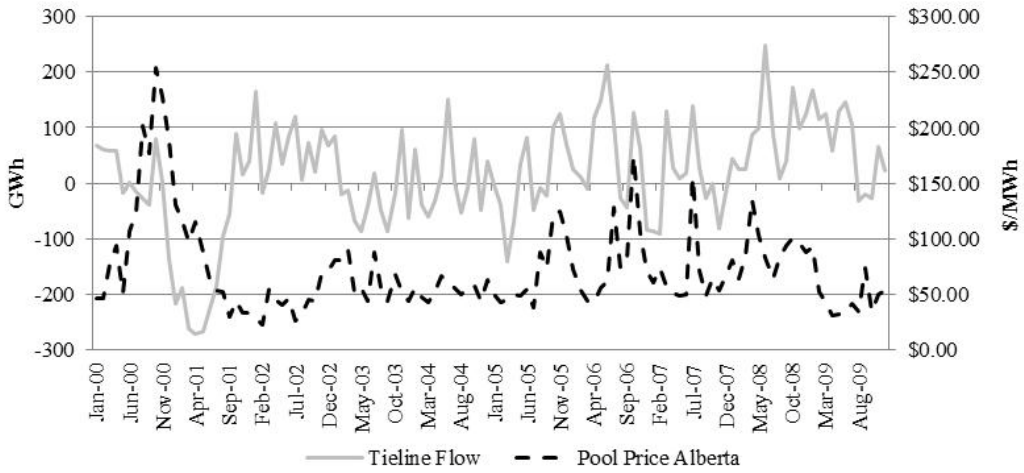

Figure 4.5: Alberta-BC tie line flows and Alberta Pool price

Interestingly, the same pattern does not emerge with the Mid-C prices and U.S. intertie flows. This may be because BC energy exported to the U.S. is, in fact, moving farther southward towards the California/Oregon Border (COB). In that case, the price dynamics at Mid-C may not capture the true value accruing to BC's U.S. exports. Further evidence is provided in Figure 4.6, where net volumes and net revenues to BC are plotted.

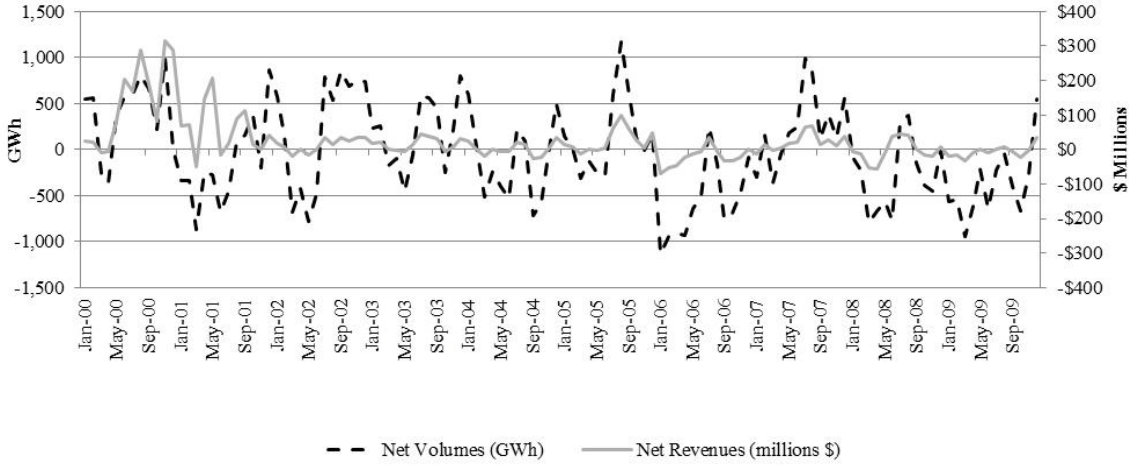

Figure 4.6: BC net trade volumes and net revenues.

In December 2000, BC was a net importer of a small amount of energy (< 1 GWh), but it received over $288 million dollars in net revenues that month. Export volumes in December 2000 were nearly identical to import volumes (577.09 GWh vs. 578.04 GWh) but export revenues were four times larger than import payments ($387 vs. $99 million). In this instance, BC export revenues exceeded import costs. This was not an isolated occurrence; there are 21 months over the past nine years of NEB data where net revenues were positive and net volumes were negative. The differences between energy volumes and energy revenues may be explained by the province's net export profile.

Net Export Profile

Under the presumption that BC is using its storage capacity to maximize revenues, it is expected that BC imports would occur during low price periods (i.e., low demand hours) and exports would take place when prices are high (i.e., peak daytime hours). The sum of hourly flows on the two interties during 2008 is shown in Figure 4.7. Negative values are imports while positive values represent exports. Due to the aggregation of both positive and negative values, some information has been lost, but the general trends are indicative of provincial import/export behaviour.

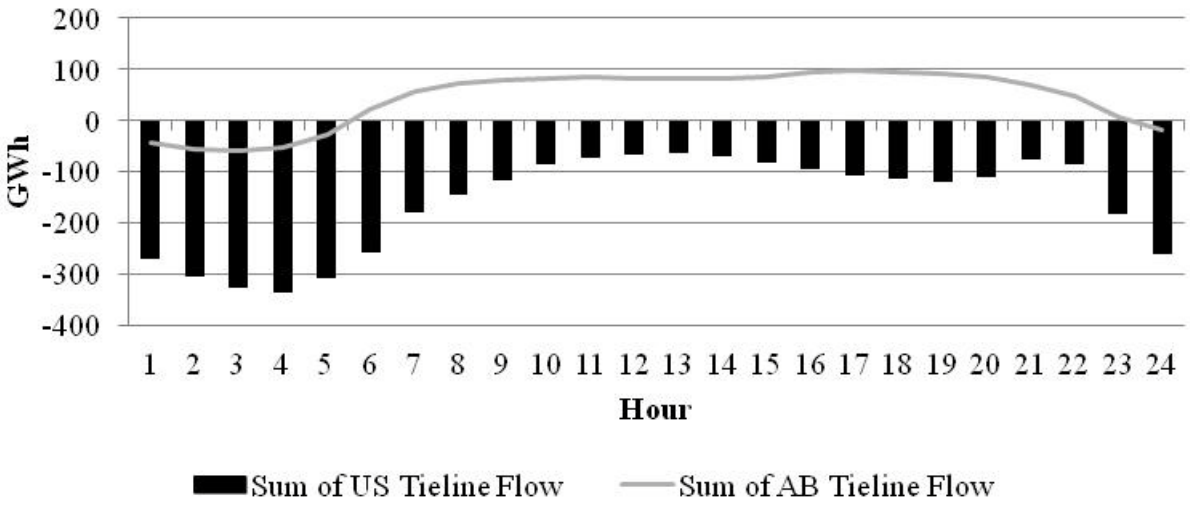

Figure 4.7: Annual average hourly flows along the BC-Alberta and BC-U.S. interties

The expected import/export pattern is clear in Figure 4.7. Net exports to Alberta increased from HE 7 to HE 22, which corresponds exactly to Alberta's peak demand hours.[43] During Alberta's off-peak hours, BC is importing. To some extent, BC is practicing the same revenue maximizing strategy with the U.S. as imports are relatively larger during off-peak hours and are reduced during peak times.

British Columbia's export pattern varies with its intended market. The east-west relationship is diurnal. BC can take advantage of low Alberta night time prices by importing energy and saving water for future electricity generation. In the daytime, when prices are higher in Alberta, BC exports energy increasing its revenues. With respect to the U.S. markets, it is important to recognize that BC exports and imports of electricity are small relative to the overall size of the market and that the export-import relation is less diurnal than it is seasonal. During winter, BC requires more electricity for heating (because it is colder) and lighting (because it is

[43] In Alberta, the time is defined as 'hour ending' or HE which refers to the 60 minute period ending that hour. For example, HE 7 includes the time between 06:00 and 07:00.

dark longer). Farther south, principally in California, Arizona and Nevada, the demand for electricity is lower in winter than during summer because heating needs are not onerous and the summer-winter contrast between daylight and night is less pronounced. Hence, there is less demand for electricity in winter than summer, while demand in BC (and much of the northern states in the WECC system) is higher. During summer (June, July, August, September), BC requires less electricity, but demand is high in the United States, mainly for air conditioning. California is particularly concerned with electricity supply for their cooling needs over the period they define as summer – June through September. Therefore, we would expect BC to export power (or import less) during this period.

This pattern is confirmed in Figure 4.8, where we observe that BC is generally a net exporter of electricity to the United States in the summer and a net importer during the rest of the year. Notice that BC does import electricity from the U.S. some summers (2001, 2002, 2004, 2006, 2008 and 2009), but the amount is much less than what is imported at other times of the year. The reasons why BC imports electricity in the summer are unclear although it could be related to low water levels domestically or relatively low price levels for electricity in adjacent markets.

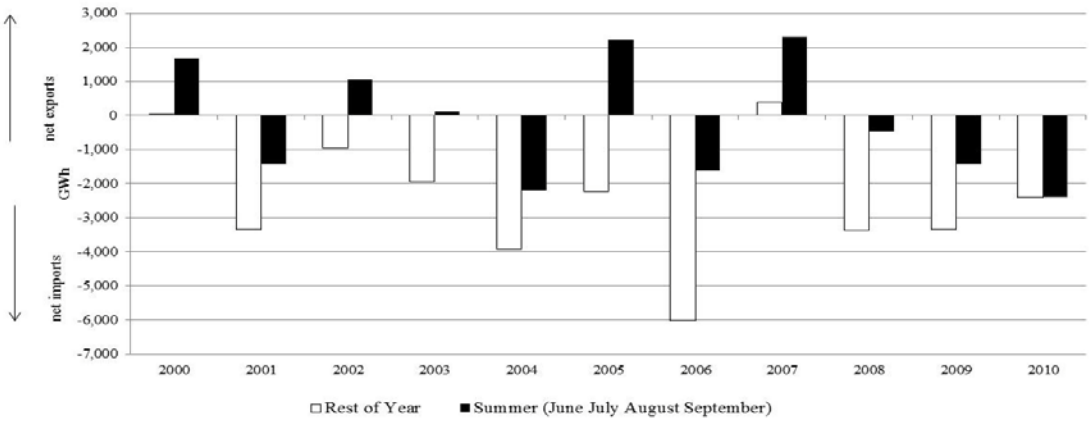

Figure 4.8: Historic seasonal volumes on the BC- U.S. tie line

Not included in the discussion of the exchange between the U.S. and British Columbia is the issue of Columbia Treaty power that is generated in the United States but attributed to BC.

4.3 Model of BC Power Systems

The purpose of our model is to address the question of whether or not BC could have attained energy self-sufficiency given its currently available resources. We model the BC electricity system concentrating on the two largest generating facilities and the downstream facilities affected by their outflows.

As discussed above, the electricity sector in British Columbia is dominated by hydroelectric generation. In 2008, hydroelectric generation accounted for approximately 86 percent of the electricity supplied in BC (Province of British Columbia, 2008). For this reason we focus on the province's hydroelectric generating assets, although we allow for thermal units to be used as required and for imports and exports when it proves economically feasible.

Hydrometric and Hydroelectric Generating System Data

Data for historical inflow, outflow and reservoir elevation are from the Environment Canada Data Explorer (ECDE) and the HYDAT Database, both distributed by the Water Survey of Canada (WSC).[44] The average inflows are calculated as the average of the inflows prior to dam construction; average outflows and average reservoir elevations are the averages after dam construction. Information about hydroelectric generating capacity, constraints and technical specifications are primarily from Sawwash (2000) and BC Hydro (2008c).

Electricity Demand

Historical balancing authority load data are available from BC Hydro (BCTC, 2010b).

[44] ftp://arccf10.tor.ec.gc.ca/wsc/software/HYDAT/

The data are provided as hourly load including imports and exports, and have been aggregated to derive daily demand. This is shown in Figure 4.9.

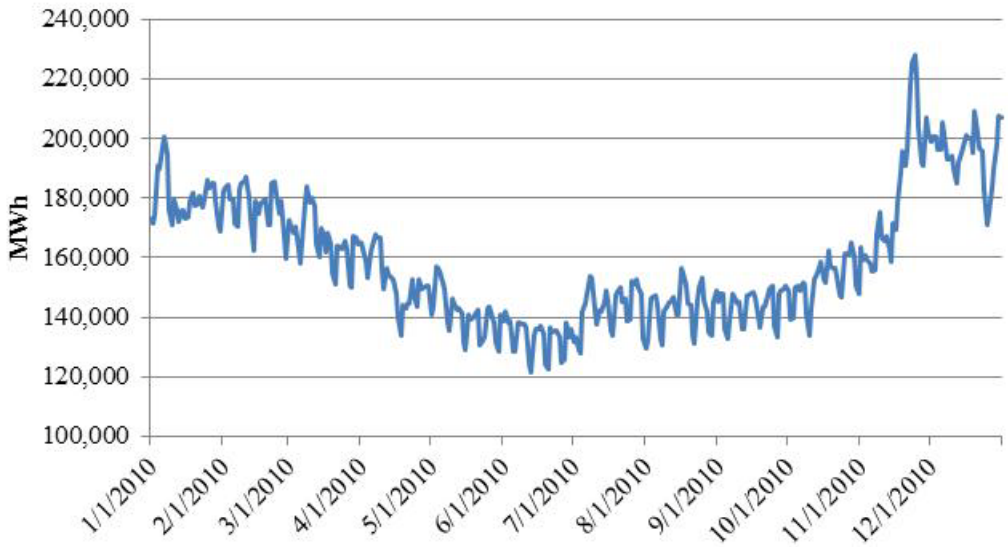

Figure 4.9: 2008 BC daily demand in MWh

Financial Data

Data for revenue and costs are from the BC Hydro *2008 Annual Report*. A summary of the financial information is provided in Table 4.5.

Table 4.5 BC Hydro Revenues and Costs, 2007-2008

Revenues		$ millions		Electricity GWh		$/MWh
		2008	2007	2008	2007	2008
	Domestic	2,944	2,786	53,300	52,911	55.23
	Trade	1,911	1,409	51,815	41,336	36.88
	Electricity	1,053	904	37,450	33,372	28.12
	Gas	858	502	14,365	7,964	59.73
Costs						
	Hydro generation	318	259	51,655	44,886	6.1
	IPP Purchases/ other long term contracts	477	363	7,765	6,041	61.39
	Gas for thermal generation	64	78	613	1,060	104.67
	Allocation from (to) trade energy	-126	67	-2412	656	56.04

Source: BC Hydro (2008c)

Average daily electricity generation for select power systems is reproduced in Table 4.6.

BC Hydro is permitted to earn an allowed return on equity. Tariff rates are based upon BC Hydro's cost and equity forecast. Uncontrollable costs are related to unanticipated water inflows, energy prices (including thermal fuel costs), and trade revenues (BC Hydro, 2008c).

Table 4.6: Electricity Requirements and Sources of Supply, 2008

Requirements	Capacity (MW)	GWh	%		
Domestic	12,280	53,300	55.3%		
Electricity Trade		37,450	38.8%		
Subtotal		90,750	94.1%		
Line Loss and System Use		5,676	5.9%		
Total		96,426	100.0%		
Sources of Supply					
Hydroelectric Generation	Capacity (MW)	GWh	%	Daily Average (GWh)	Capacity Factor (%)
G.M. Shrum	2,730	16,477	17.1%	45.019	68.7%
Revelstoke	1,980	9,496	9.8%	25.945	54.6%
Mica	1,805	8,562	8.9%	23.393	54.0%
Kootenay Canal	583	3,083	3.2%	8.423	60.2%
Peace Canyon	694	4,054	4.2%	11.077	66.5%
Seven Mile	805	2,880	3.0%	7.869	40.7%
Bridge River	478	2,793	2.9%	7.631	66.5%
Other	1,167	4,795	5.0%	13.101	46.8%
Subtotal	10,242	52,140			
Thermal Generation					
Burrard	950	260	0.3%		
Other	137	353	0.4%		
Purchases Under Long Term Commitments		11,878	12.3%		
Purchases Under Short Term Commitments		32,281	33.5%		
Exchange Net		-485	-0.5%		
Total		96,427	100.0%		

Source: BC Hydro (2008c)

Trade revenues are generated through the sales of electricity either to the U.S. or Alberta. These are calculated on the basis of the 2008 historical average import and export prices shown in Table 4.7.

Table 4.7: BC Import and Export prices

	Import Price ($/MWh)	Export Price ($/MWh)
Alberta	$118.32	$45.42
U.S.	$76.46	$64.99

Source: National Energy Board (2008), Government of Alberta (2008)

Constrained Optimization Model

The model described in this section focuses on power generation in BC, but is similar to the linear programming model outlined by van Kooten (2012) and Scorah (2010). The model is specified as a constrained maximization problem where the objective is to determine the daily electricity generated by each asset that maximizes annual profit subject to minimum energy supply requirements and technical constraints on energy generation. The objective function is formalized as:

$$max_{Gen_{t,G}}\, \pi = \sum_{t=1}^{366} \begin{bmatrix} P_{BC} \cdot load_t - \sum_G C_G \cdot Gen_{t,G} \\ +P_{E,AB} \cdot Export_{AB,t} - P_{I,AB} \cdot Import_{AB,t} \\ +P_{E,US} \cdot Export_{US,t} - P_{I,US} \cdot Import_{US,t} \end{bmatrix} \quad (4.1)$$

where $Gen_{t,G}$ is the energy generation from power system G in period t; P_{BC} is the domestic price of electricity; $load_t$ is the daily load in MWh; C_G is the average generation cost of generator source G; $P_{E,AB}$ and $P_{E,US}$ are the average export prices per MWh for Alberta and BC, respectively; and $P_{I,AB}$ and $P_{I,US}$ are the average prices of imports from Alberta and U.S., respectively.

Total energy generation must exceed domestic demand plus net exports for each jurisdiction ($NX_{AB,t}$ and $NX_{US,t}$) in each period; thus, the demand constraint is

$$\sum_G Gen_G - load_t - NX_{AB,t} - NX_{US,t} \geq 0, \forall t \qquad (4.2)$$

BC's electricity is predominately generated by large-scale hydroelectric plants, which allow a certain level of control over reservoir levels and the amount of water released through turbines. Hydroelectric power generation at plant *h* is given by the equation:

$$Gen_{t,h} = \frac{9.81 \times \eta \times H_{t,h} \times q_{t,h} \times d}{3{,}600 \times 1000}, \forall t \qquad (4.3)$$

where η is the efficiency of a Francis turbine, $H_{t,h}$ is the beginning-of-period head height (m), $q_{t,h}$ is the rate of flow through the turbine (m^3/s) and *d* is the number of hours in period *t*. The equation is divided by 3,600 to convert seconds to hours and by 1,000 to convert power generation from kWh to MWh. For simplicity, the beginning-of-period head height is used instead of average effective head height. Both $H_{t,h}$ and $q_{t,h}$ are choice variables and, following Loucks, Stedinger, and Haith (1981), equation (4.3) is linearized for tractability using the equation:

$$q_{t,h} \times H_{t,h} \approx q_t^0 \times H_t^0 + q_t^0(H_t - H_t^0) + (q_t - q_t^0) \times H_t^0 \qquad (4.4)$$

$$= q_t^0 \times H_t + H_t^0 \times q_t - q_t^0 \times H_t^0$$

where H_t^0 and q_t^0 are the reservoir's average head height and average outflow, respectively, gathered from hydrometric data. Following Jha, Yorino, Ariaratne, Iwata and Oe (2008), head height is then related to reservoir volume by

$$H_{t,h} = Hmin_h + \sqrt{Vol_{t-1,h}/R_h}, \forall t \qquad (4.5)$$

where *Hmin*, is the minimum regulated head height at reservoir *R* and R_h is a reservoir specific constant derived by solving equation (4.5) using the maximum regulated head heights and reservoir volumes. Constraint (4.5) requires the use of a nonlinear programming algorithm; the

problem may be converted to a linear program by assuming reservoir dimensions and replacing (4.5) with the standard formula for the volume of a rectangular prism.

Furthermore, the change in reservoir volume is determined by inflows, outflows and the volume of water spilled due to reaching reservoir storage capacity. This constraint is formulated as

$$Vol_{t,h} = Vol_{t-1,h} + \left(i_{t,h} - q_{t,h} - s_{t,h}\right) \times 24 \times 3600, \forall t \qquad (4.6)$$

where volume is measured in m^3 and inflow (i), outflow (q), and spillage (s) are measured in m^3/s, but converted in (4.6) to daily flows. Inflows are deterministic and available from hydrometric data.

Finally, BC Hydro sets targets for end-of-year reservoir levels. Specific details are unavailable, so arbitrary year-end reservoir levels are specified as a proportion (e) of initial storage levels. The volumes modeled are the live storage volumes:

$$Vol_{T,h} \geq Vol_{1,h} \times e_h,\ T = 366 \qquad (4.7)$$

Transversality condition (4.7) is also important to prevent reservoir volumes from dropping to unrealistically low levels by year-end. Since the objective function does not recognize the value of storing water beyond the terminal period, reservoir volumes will naturally be drawn to zero without this constraint. As an alternative to (4.7), one might include a value function that captures the future profits from the potential energy stored at time T.

Currently, the Peace and Columbia hydroelectric systems are modeled independently, while the power generation from the remaining hydro plants is assumed to be functions of annual power generation and river inflows (i.e., annual generation multiplied by the daily inflow divided by the total annual inflow in 2008). Additionally, thermal generation is modeled as a single type,

with no identification of individual plants. Biomass, biogas and other generation methods play a minor role in BC's electricity infrastructure, and have not been modeled.

Trade between BC and Alberta is simply limited by the capacity of the 800 MW intertie while the intertie capacity between BC and the U.S. is 2,000 MW. We include a 7 percent transmission loss on both interties. These two constraints can be written as:

$$Import_{AB,t} + Export_{AB,t} \leq 800 \times 24 \qquad (4.8)$$

$$Import_{US,t} + Export_{US,t} \leq 2000 \times 24 \qquad (4.9)$$

4.4 Results and Discussion

Like river inflows, the model treats energy demand as deterministic. In reality, as BC's population, weather and economic activity changes so does energy demand. Demand from large firms is particularly volatile since consumption is influenced by export markets and world commodity prices. Because customer rates are based on average cost, which may be significantly lower than the market price of electricity, there is exposure to price risk on all consumer demand in excess of planned load (BC Hydro, 2008c). This is not considered in the model.

The model was programmed to permit consideration of various scenarios. The reliability of hydro generation in BC is most impacted by weather conditions; thus, an option is included to indicate drier or wetter than average weather conditions. Energy consumption and the generating mix are the primary factors influencing energy costs. The generating mix is influenced by energy prices, inflows, reservoir level and demand. A summary of the model outcomes is provided in Table 4.8.

Under normal demand conditions, and in the absence of thermal generation, BC is reliant on imports to meet internal load even when exports are restricted to zero, which is what we would expect given that the province's installed hydro capacity nearly matched peak load in a

below average water year.[45] Nearly 12.4 percent of the province's electricity demand must be imported from the U.S. and Alberta. By increasing the year-end reservoir targets, possibly due to the anticipation of drought, higher demand or higher future energy prices, energy costs increase as additional imports are required to meet domestic demand.

With the current set of hydrometric data and prohibiting trade with the U.S., it is not possible to decommission any of the thermal plants even when reservoir live storage volumes are permitted to decline to 50 percent of their starting values; thermal generation is still required for a few days a year. With electricity trade, BC's thermal plants become redundant; BC can export its emissions to neighbouring jurisdictions. The effect of increasing end-of-year reservoir targets is to increase imports while still keeping the expensive thermal production off-line. From a policy perspective, our analysis suggests that BC cannot meet its goals of energy self-sufficiency in conjunction with decommissioning of the Burrard power plant.

Oil, gas and mining developments are expected to increase provincial demand bymore than 3,000 GWh/year and will further strain BC's electricity generating system. In the absence of trade and thermal generation, BC would be unable to meet the increased demand regardless of how low reservoir levels are permitted to fall. One solution to the energy deficit is the Site C hydroelectric facility on the Peace River. Adding Site C as a 1,098 MW run-of-river facility makes thermal generation unnecessary, although electricity trade remains essential. As end-of-year reservoir target levels increase from 50 percent to 100 percent, the province's dependence on imports grows from 12.3 percent to 23.6 percent. This amounts to nearly 13,000 GWh of electricity. Even under the most aggressive power call plans, it is unlikely that the province could generate that amount of electricity from independent power projects; the self-sufficiency goal

[45] Installed hydroelectric capacity was 10,237 MW, peak demand was 9,548 MW, and precipitation levels were approximately 8% less than normal.

becomes even more elusive if precipitation is lower than expected.

Table 4.8 Generation by Type for Various Scenarios

Scenario	Hydro	Site C	Thermal	Imports	Exports
2008 Demand, No Thermal, No Exports, VolRes=50%	87.6%	n/a	n/a	12.4%	n/a
2008 Demand, No Thermal, No Exports, VolRes=100%	77.1%	n/a	n/a	22.9%	n/a
2008 Demand, Thermal, No Exports, VolRes=100%	89.2%	n/a	1.2%	9.6%	n/a
2008 Demand, Thermal, No Exports, VolRes=50%	76.6%	n/a	0%	23.4%	n/a
Oil/Gas Demand, Site C, VolRes=50%	78.2%	7.7%	1.8%	5.9%	6.3%
Oil/Gas Demand, Site C, VolRes=100%	65.6%	5.5%	8.1%	15.4%	5.4%
Site C, Oil/ Gas, No Thermal No Exports VolRes=50%	78.8%	8.8%	n/a	12.3%	n/a
Site C, Oil /Gas, No Thermal No Exports VolRes=100%	70.3%	6.1%	n/a	23.6%	n/a/

4.5 Conclusions

Our model results demonstrate that BC can meet domestic load based on the current generating and transmission configurations. However, decommissioning thermal units requires electricity trade, namely imports, thereby violating the province's self-sufficiency requirements. Greater constraints on year-end reservoir volumes increase the province's dependence on imports to meet load. This would be exacerbated if water inflow volumes were reduced due to drought.

British Columbia and Alberta have an entrenched trading partnership that, with greater transmission interconnections, could improve the economic and environmental situations of both provinces. Alberta with high wind penetrations faces greater grid instability (see Chapter 3). The inability of slow ramping thermal generation to react to wind ramping events leads to grid reliability issues, while British Columbia faces a shortage of energy. Increasing the size of the Alberta-BC intertie and improving scheduling practices would benefit both provinces. Alberta would receive electricity from BC's fast-ramping hydroelectric facilities on an 'as-needed' basis to counteract wind ramping events. BC could import excess wind supply from Alberta and store

water for future production.

At present, there is little (or no) political will to increase transmission between the provinces. Alberta's own generators receive greater revenues via higher Pool prices when imports are restricted. BC's ability to be the marginal supplier during critical supply periods in Alberta allows Powerex to capitalize on high prices; historically, BC has received the highest average price compared to all other generator assets in the Alberta market.

BC's profitable export opportunities to the U.S. are dwindling. California continues to create roadblocks that would prevent BC electricity entry into the lucrative renewable portfolio standard markets. The California Air and Resources Board believes BC Hydro (via Powerex) is engaging in 'resource shuffling' (see Chapter 2), essentially buying low-priced nighttime thermal generation from Alberta while storing water and selling hydro output without accounting for transferred CO_2 emissions.

Exacerbating the export issue is the fact that the Bonneville Power Authority (BPA) and the Mid-C market are going to be in surplus supply position more frequently as wind capacity in that region doubles. The freshet (spring runoff) occurs at the same time for BC Hydro's and BPA's hydroelectric facilities, so both have a surplus of energy at the same time of year. This sometimes drives prices in the Mid-C market into the negative range. BPA's reluctance to sell negatively priced electricity led to curtailment of wind generators in that region, while allowing hydroelectric generation to continue – a protocol BPA calls environmental re-dispatch. Environmental protection, particularly as it related to fish health and habitat, was BPA's rationale for the unequal treatment of hydro and wind generators. Area wind owners filed a claim with the Federal Energy Regulatory Committee (FERC) that curtailing wind generators violated the U.S. Federal Power Act. FERC upheld the claim and ordered BPA to stop curtailing wind as

a system balancing protocol. BPA was given 90 days to file an alternative plan. However, BPA asked for a re-hearing and ruling on the environmental dispatch protocol. In the interim, BPA and BC Hydro have renegotiated their non-treaty storage agreement, increasing the amount of water that the U.S. can store in the Kinbasket reservoir.

In chapter 5, we examine the interdependency between the Alberta and British Columbia electric grids. As discussed above BC is dependent upon power generation from Alberta. Chapter 3 illuminated the importance of fast ramping generation to offset the variability of wind ramping events. In the following chapter, we examine the economic and environmental effects of increasing the size of the intertie between Alberta and BC under a range of scenarios for both water and wind.

Chapter 5: The Economics of Storage, Transmission and Drought: Integrating Variable Wind Power into Spatially Separated Electricity Grids[46]

5.0 Introduction

Intermittency is the greatest obstacle to the seamless integration of wind generated power into electricity grids. When there is no wind, no power is generated; the wind comes and goes, and does not always blow with the same intensity – and this uncertainty has a cost. In addition to the direct costs of wind power (e.g., construction of wind turbines, land costs, upgrading and construction of transmission lines, environmental costs), there are indirect costs associated with (1) the need for additional system reserves to cover intermittency and (2) the requirement to adjust the output from existing generating assets as wind power fluctuates. If wind assets fail to deliver expected output, backup reserves must cover the shortfall; if excess wind power enters an electricity grid and there is no provision to curtail wind generation, any electricity generated by wind turbines is 'must run' (non-dispatchable) and existing assets must adjust output to accommodate it, which could be costly (Lund, 2005; van Kooten, 2009). To mitigate the indirect costs and make more efficient use of wind resources scattered over a large region, greater integration of electrical systems has been proposed (Pöyry, 2011), with high capacity transmission lines tying together wind farms at various locations and facilitating storage of intermittent power behind large-scale hydro dams, both presumably to level out wind variability.

In this chapter, we investigate the potential to tie together two independent electricity grids that have very different generating mixes and are only weakly linked – the electricity grids of British Columbia and Alberta. The former grid is characterized primarily by large-scale

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hydroelectric dams with ample reservoir storage, the other by fossil fuel thermal capacity and rapidly increasing wind generating capacity. Hence, there is the potential for the independent system operators to mutually benefit from better integration of their grids to take advantage of the ability of hydro assets to store large but highly variable wind power.

Climate change is expected to adversely impact water availability in Alberta and British Columbia, increasing droughts and affecting how water will be allocated among competing uses. In the past, there have been conflicts over hydroelectric development on the BC side of the Peace River (Canada, Alberta & Northwest Territories, 1996), and concern about potential water shortages in southern Alberta caused by high demands due to urban growth and secondary oil recovery (Alberta Environment & Water, 2002). Climate mitigation policies emphasize greater reliance on renewable sources of energy, especially hydropower and wind, but this will increase the stress on water resources.

Impending climate change will greatly complicate the water-energy interface because carbon dioxide emission mitigation strategies increase demand for hydropower that is thwarted by reduced water availability. The storage provided by hydro reservoirs is ideal for integrating the vast intermittent wind power resources east of the Rockies, but climate-induced droughts are projected to reduce hydroelectric generation that, in turn, exacerbates the need for wind to replace the lost hydro energy and to offset increased CO_2 emissions from greater use of ubiquitous and cheap fossil fuels that inevitably replace some of the lost renewable hydropower.

Given that BC hydro facilities are important for storage of wind power generated in Alberta but that the extant transmission intertie between the two grids has low capacity, one objective of the current research is to determine the benefits of greater integration of two disparate grids. Other objectives are: (1) to investigate the potential of BC’s vast hydro storage

capacity to facilitate the optimal use of wind energy east of the Rockies; (2) to model the potential effect that drought could have on hydroelectric generating capability in these provinces and the implications for future energy stability and supply; and (3) to investigate the impact that drought could have on the 'performance' of wind generation in terms of wind penetrability into the grid and on overall CO_2 emissions from production of electricity. Might drought reduce the effectiveness of renewable wind energy because drought reduces the capacity to store intermittent wind power as potential energy behind hydro dams? And what are the likely economic costs of reducing CO_2 emissions using wind-generated power with hydro storage under current versus more frequent drought conditions?

To address these objectives, we develop a mathematical programming model of the BC and Alberta electricity grids and the intertie between them. The model builds on earlier work by van Kooten and Wong (2010); van Kooten (2009); Prescott and van Kooten (2009); Maddaloni, Rowe and van Kooten (2008, 2009); Benitez, Benitez and van Kooten (2008); Prescott, van Kooten and Zhu (2007); Weber (2005); Lund (2005); and Loucks, Stedinger and Haith (1981). The numerical model is solved in an Excel-MATLAB-GAMS software environment (Wong 2009).

5.1 Literature Review

In one of the earliest assessments of the costs of integrating renewable energy within a hydroelectric power system, Bélanger and Gagnon (2002) modeled Quebec as an isolated power system with no transmission interties to grids outside the province. The wind output was calculated using a power curve, with hydrometric data (see Chapter 4) used to determine Quebec's hydropower output. The authors showed that wind penetrations of more than 10 percent would require additions to Quebec's hydro capacity to handle the increases in variability

from wind output.

A later storage paper by DeCarolis and Keith (2006) included a cost-benefit analysis of Compressed Air Energy Storage (CAES) in combination with increases in the integration of intermittent renewables. The model included conventional fossil fuel generation, wind and compressed air storage, and was used to determine the optimal generation mixture to minimize costs given a carbon tax. The authors allowed the generation mix to change over time to adapt to increased wind power, while assuming that fossil fuel generation consisted only of open-cycle gas turbine (OCGT) peak power plants and combined-cycle gas turbine (CCGT) base-load plants with no coal generating capacity (as it was considered too expensive under a carbon tax). The gas generators were assumed to have a constant efficiency over the output range, while the costs of using gas plants for regulation were ignored as OCGT plants can follow load shifts within the hourly time step employed. Transmission constraints between regions were fixed, and wind-generated power output data were simulated using wind speed data and a power curve. Results indicated that wind penetrations of up to 50 percent of generating capacity were cost competitive with coal that included carbon capture and storage, as well as with other technologies designed to reduce carbon emissions in electricity generation.

Using pumped storage in the Alberta power system, Benitez, Benitez and van Kooten (2008) evaluated the cost-effectiveness of using wind energy to curtail GHG emissions. Their model included constraints that limit the speed at which fossil fuel generators can ramp up and down, as well as variable head at the hydroelectric dams. Three scenarios were evaluated: one with no wind and two with increasing quantities of wind replacing coal generation. The wind output was generated using power curves and wind speed data. The authors showed that variability increased with wind penetration and that new gas peaking units were required to meet

the challenges posed by wind variability even with the inclusion of hydroelectric storage dams (although the scope for hydroelectric facilities is severely constrained in Alberta). The cost of including the new wind power to the system was estimated to be \$41-\$56 per tCO_2. Similarly, Prescott and van Kooten (2009) used a model that selected an optimal generating mix for integrating wind into the Alberta electricity grid to estimate the costs of reducing emissions at \$66/tCO_2.

A number of authors have employed mathematical programming models to investigate the integration of wind power into the small Vancouver Island electricity grid. The earliest of these found that there is not always sufficient wind when power is needed, and even the development of large wind resources alone would be insufficient to meet the electricity needs of Vancouver Island (Prescott, van Kooten & Zhu, 2007). The cost of reducing CO_2 emissions was estimated to be around \$100/tCO_2, primarily because the Island grid relies mainly on hydropower from the mainland. In a related paper, Maddaloni , Rowe and van Kooten (2009) considered the effect of transmission constraints on the integration of renewable wind technologies, showing that, as wind penetration increases, the costs imposed on other generating assets rises and there is a need to increase transmission capacity. Specifically, the authors found that wind penetrations exceeding 20 percent result in negative net benefits for the Vancouver Island system.

Finally, using Vancouver Island load data as a proxy for a small power system, Maddaloni, Rowe and van Kooten (2008) examined the effects of integrating wind power into electricity grids with three different extant generating mixes – a predominantly hydroelectric system similar to BC, a mix of fossil fuel and hydroelectric generation similar to the Northwest Power Pool, and a mix of generation heavily weighted toward nuclear and fossil-fuel generation

similar to that characterizing U.S. power production. As wind power penetration increased (defined as wind generating capacity relative to peak load), the increased capital costs of installing wind turbines in a fossil-fuel based system overwhelmed the reductions in fuel costs and CO_2 emissions that are the primary benefits of wind. Costs of CO_2 uptake were also high in the primarily hydroelectric and the nuclear-coal grids because wind often displaced power production from hydro and/or nuclear facilities that produced little greenhouse gases.

With calibrated hydro and wind data derived from actual observations, Denault, Dupuis and Couture-Cardinal (2009) use a simulation-based risk analysis to investigate annual energy inflows to the predominately hydroelectric Quebec electricity grid, focusing on the geographic dispersion of wind farms. The simulation model uses combinations of wind-generated power and hydropower to meet the load. The authors then examined water inflow deficits over the long term, with wind power as the primary means of diversifying the energy inflow portfolio, and concluded that wind power could provide substantial diversification in power supply for wind penetrations up to 30 percent.

In this study, we consider the economic and CO_2 emission-reduction benefits of integrating the Alberta and British Columbia electricity grids to take advantage of Alberta's capacity to generate wind power and BC's capacity to store energy behind hydro dams. As an additional feature, we examine the costs imposed on such an integrated system when climate change results in more frequent droughts.

5.2 Methods

The Alberta electricity grid is predominantly fossil fuel based. In addition to 5,946 megawatts (MW) of coal and 5,116 MW of natural gas-fired capacity, Alberta has upwards of 871 MW of hydroelectric assets and, as of 2009, nearly 600 MW of recently integrated wind-

generating capacity. Hydro assets are primarily run-of-river as there is little storage available in the Alberta system. The BC system, on the other hand, is predominantly hydro based with a total installed generating capacity of over 11,000 MW; it comprises 30 primarily large-scale hydroelectric generating facilities, some run-of-river facilities and several thermal power plants (including a 900 MW capacity OCGT peak power plant known as Burrard). A transmission intertie exists between the two provinces, but, as discussed below, its capacity is currently limited by operating constraints on the Alberta side of the border. An outline of available capacities and the link between the systems is found in Figure 5.1.

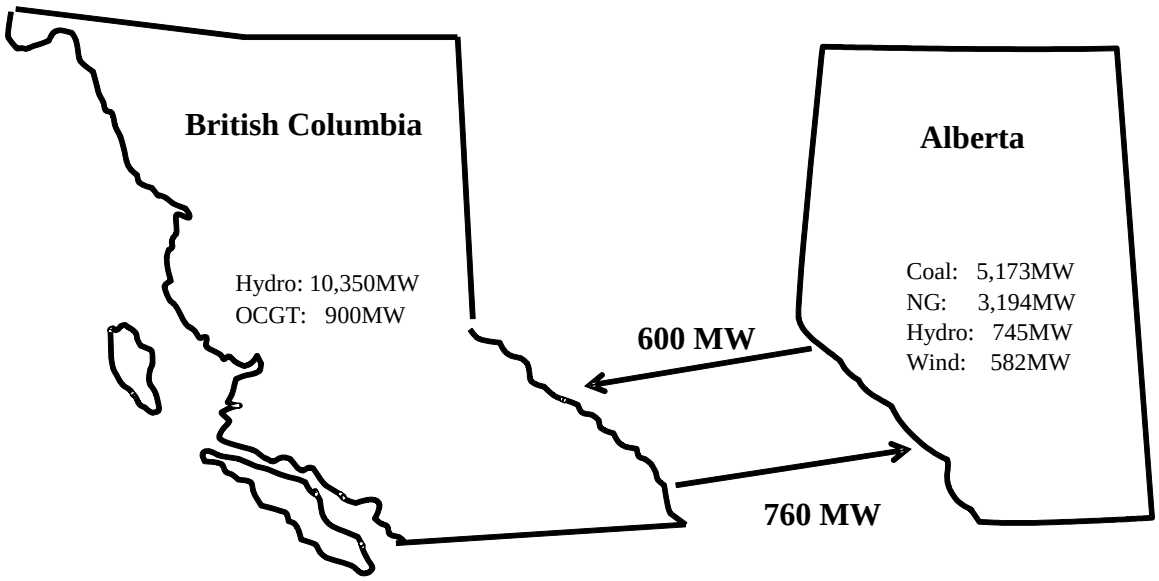

Figure 5.1: Alberta and BC electricity systems and transmission interties

5.3 Model

In this section, we extend earlier models by Prescott, van Kooten and Zhu (2007), Benitez, Benitez and van Kooten (2008), and Prescott and van Kooten (2009) to capture the Alberta power system in greater detail, but also take a different approach to scaling the wind output. The linear mathematical programming model minimizes total variable costs subject to the operating constraints in the two power systems and the transmission intertie constraint. The

objective is to minimize fuel costs (b_i) plus the variable operating and maintenance costs (OM_i) of each generator *i* multiplied by the generator output ($Q_{i,t}$) in each period t and then summed over the entire planning horizon:

$$Min_Q\ TC = \sum_{i=1}^{24\times d}\left[\sum_i (OM_i + b_i)Q_{i,t}\right] \qquad (5.1)$$

where *d* is the number of days (taken to be 365 so that there are 8,760 hours in the model).

The costs of the two power systems are jointly optimized, but the loads in each province must be met separately. For each province (*P*), the sum of the generator outputs in each period must equal the customer load ($L_{t,P}$), net exports ($X_{t,P}$) and wasted power ($W_{t,P}$). This constraint can be written as:

$$\sum_i^{N_p} Q_{i,t,P} - L_{t,P} - X_{t,P} - W_{t,P} = 0, \forall P = AB, BC;\ \forall t \qquad (5.2)$$

where there are *NP* generators in province *P*. Net exports refer to power delivered along the BC-Alberta intertie, whether from Alberta to BC or in the other direction.

If loads and generation are not equal, there will be a deviation from the scheduled interchange of electricity in an interconnected power system, or a deviation from the target system frequency in a closed power system. Instead of including these power system characteristics, we employ the notion of wasted power, which captures events where unusable excess power is produced because generators cannot be ramped down quickly enough or have already reached their minimum generation (and cannot reduce output further). In practice, the system operator would curtail unwanted generation by not accepting power from the source most

capable of regulating production, which is usually a hydro or wind source.[47] In our model, the waste variable constitutes a measure of the wasted wind energy that cannot be used by the Alberta or British Columbia electricity grids (or elsewhere if there are opportunities for export to other regions).

Hydroelectric power generation is simplified to keep the model linear. We assume that the output of a hydroelectric generator h ($\subset i$) at time t is a function of η_h the generator efficiency, g the gravitational constant (m/s^2), d the density of water (kg/m^3), $F_{t,h}$ the flow of water through the penstock (m^3/s), H_h the fixed head height (m), and the factor 10^{-6} used to convert the output in watts to MW:

$$Q_{t,h} = \eta_h \times g \times d \times F_{t,h} \times H_h \times 10^{-6} \qquad (5.3)$$

The simplification here is that head height is held constant. A more detailed model would allow for a head height that is a function of the reservoir volume. Including this detail, however, would result in a non-linear model requiring significantly longer solution times while providing little additional insight as to how wind power can be effectively integrated into the two electrical systems.[48]

The volume of water stored behind hydro dam h at time t, $V_{h,t}$, is equal to the water behind the dam in the previous period plus inflows during the period ($I_{h,t}$), minus the sum of the flows into the penstocks ($F_{h,t}$) and the water that is spilled ($S_{h,t}$):

$$V_{h,t} = V_{h,t-1} + I_{h,t} - F_{h,t} - S_{h,} \qquad (5.4)$$

[47] Hydro power output can be varied quickly by changing the amount of water entering the turbines (much like changing the flow of gasoline to an automobile engine by changing the pressure on the accelerator. Wind power is curtailed by changing the orientation of the turbines relative to the wind direction.
[48] However, see Chapter 4 for a method of linearizing the problem.

Rivers in British Columbia and Alberta often have a legislated minimum river flow, which requires that the water flowing into the penstocks plus the spilled water be greater than the minimum river flow:

$$F_{h,t} + S_{h,t} \geq F_h, \ \forall \ h \qquad (5.5)$$

Further, the hydro reservoirs have storage limits:

$$V_{h,t} \leq max \ V_h, \ \forall \ h \qquad (5.6)$$

where the volume of water in each reservoir at any given time may not exceed the maximum volume of the reservoir.

Generators cannot exceed their capacity and their output must be above a minimum level or they will shut down:

$$Q_{i,t} \leq max \ Q_{i,t}, \ \forall \ i, t \qquad (5.7)$$

$$Q_{i,t} \geq min \ Q_{i,t}, \ \forall \ i, t \qquad (5.8)$$

We do not model the shutdown and startup of individual generators per se, because several power plants or generating sources are combined into single units for computational ease. Thus, the lower bound on generation reflects the necessity to keep certain generating sources at an adequate level of output for load balancing and reserve purposes. Given the nature of thermal generating assets in Alberta and British Columbia, it is also necessary to ensure that generator output between any two periods (between one hour and the next) does not exceed the ability of output from a generating source to ramp up or down. This is a critical constraint that frequently binds for Alberta's coal assets and particularly when highly variable wind enters the grid. The constraints are specified as follows:

$$Q_{i,t} - Q_{i,t-1} \leq R_i, \ \forall \ i \qquad (5.9)$$

$$Q_{i,t-1} - Q_{i,t} \leq D_i, \ \forall \ i \qquad (5.10)$$

where R_i refers to the amount by which generator i can ramp up between two periods and D_i the amount by which it can ramp down.

The Alberta and BC grids are connected via two 138 kV lines and one 500 kV line. Thus, we model a single transmission line linking the provinces. The Western Electricity Coordinating Council (WECC) rates the intertie between Alberta and BC at 1,000 MW capacity for export from Alberta and 1,200 MW for import into Alberta; however, as illustrated in Figure 5.1, operating limits within Alberta effectively de-rate that intertie, restricting the export value to 600 MW and the import value to 760 MW (IEA, 2008). In this study, we model zero transmission, the normal operating limits, and the limits as if Alberta had invested in improving internal infrastructure so that the transmission line can operate at capacity.

We require that exports from one province be equal to imports into the other province (and ignore line losses). In addition, more cannot be imported by one province than the export maximum of the other province, and a province cannot export more than its maximum. For convenience, it is assumed that there is no connection to other grids in North America. The forgoing requirements can be represented by three constraints:

$$X_{BC} + X_{AB} = 0 \qquad (5.11)$$

$$X_{BC} \leq max\, X_{BC} \qquad (5.12)$$

$$X_{AB} \leq max\, X_{AB} \qquad (5.13)$$

Wind Output Information

Electricity generated using the wind is treated as self-scheduled generation that the

system operator must integrate into the system. The modeling of wind data inputs differs from some of the approaches employed by others (e.g., see Soder & Holttinen, 2008). Instead of physically modeling the wind (see Dua, Manwell & McGowan, 2008), or scaling or shifting an observed wind profile (Maddaloni, Rowe & van Kooten, 2009), we construct wind output profiles for different time periods during the year based on time-series observations and then synthesize the new wind outputs in a manner similar to MacCormack, Zareipoour and Rosehart (2008). We prefer this approach when the available wind speed data are insufficient for proper modeling of the mechanics of wind generators and scaling of wind output.

To construct the wind output profiles, we use the five-minute observations of wind-generated output in Alberta over the latest available year. We begin by subtracting the annual mean from the whole series, thereby giving a mean-zero residual series for the whole year. Then the monthly averages are subtracted from each month's data giving mean-zero residuals for each month. This is then done for days and hours until there is a mean-zero residual for each five-minute period. From this mean-zero series a distribution was fitted and new values were drawn from the distribution to give a new wind series. Finally, the averages are added back into this new series to give a new annual wind output profile that represents existing capacity in Alberta. To generate profiles with twice the wind power output, the output profile created using averages is doubled and a new random mean-zero series is overlaid on top. This is doubled again for the 4× wind scenario.

A summary of the data employed in the mathematical programming model is found in Table 5.1. The generating capacities of Alberta's thermal and hydro units are based on available generating capacity figures published by the Alberta MSA (2009a). British Columbia data are based on 2009 operational forecasts of existing and committed supply capacities as detailed in

the BC Hydro *Long Term Acquisition Plan Application* (2008).

Table 5.1: Summary of Key Data used in the Simulation Model

Item	Alberta	British Columbia
Average load	7,962	7,005
Maximum load	9,806	10,885
Minimum load	6,411	4,703
Average wind output (MW)	175	—
Capacity Factor of Wind (percent)	30%	—
Imports along intertie (TWh)	0	2.706
Exports along intertie (TWh)	2.706	0
Average basin inflow into major reservoirs (m3/s)[a]	79.7	1,637.5
Hydroelectric generating capacity (MW)[b]	718	10,344
Thermal generating capacity (incl. biomass) (MW)[c]	9,039	1,476
Maximum peak load generating capacity (MW)[d]	272	—

[a] For Alberta, these are the Big Horn and Brazeau reservoirs; for British Columbia, these include Kinbasket and Revelstoke on the Columbia River and Williston Reservoir on the Peace River. Inflow into the Peace Canyon reservoir equals outflow from the Bennett Dam (Williston reservoir).
[b] Includes run-of-river hydro: 243 MW in Alberta, 3,135 MW in British Columbia.
[c] Includes biomass and some co-generation power that are considered must run.
[d] BC relies primarily on hydroelectricity for meeting peak load demand, with the Burrard power plant used only sparingly (< 40 hours annually).

5.4 Model Results

We investigate scenarios with normal precipitation and with drought, with high and low wind energy outputs, and with differing intertie transmission capacities. Drought conditions were estimated from historical hydrometric data (see Chapter 4). The last severe drought in Alberta and British Columbia was in 2001-2002 when river flows were reduced to 37.5 percent of their peak flows. This corresponded to the ‘electricity crisis’ (characterized by rolling black outs) in California, which relies heavily on hydropower from the U.S. Pacific Northwest (which was also affected by drought). In this application, we modeled drought by reducing water inflows to 37.5 percent of normal.

Under drought conditions and with no transmission between Alberta and British Columbia, there is no solution to the mathematical programming model. When water levels in British Columbia are low, the province must import electricity. In the model, energy must be

imported from Alberta, but there was insufficient transmission capacity to import the required power. Of course, in practice BC imports power from the United States, but this is not modeled here. Despite the U.S. link, reduced precipitation will negatively impact British Columbia's energy security. Without significant increases in generating capacity, the goal of energy self-sufficiency as expressed in the *BC Energy Plan* (2009) may well be unattainable (see Chapter 3).

Once transmission is added to the model, British Columbia simply imports power from Alberta (just as it imported power from the U.S. during 2001-2002). The source of the imported energy depends on whether and how much wind power is produced in Alberta. Some of the key observations from the model are found in Figure 5.2. By increasing both installed wind generating capacity in Alberta and the capacity of the transmission intertie, changes occur in (1) Alberta's production of power from coal and natural gas; (2) BC's thermal generation (primarily from Burrard plant); (3) BC's hydropower output; and (4) the power flowing along the transmission intertie.

As wind output increases, Alberta's coal and natural gas generation fall. The transmission capacity between the two provinces is a key factor. As the capacity of the transmission intertie increases, more wind-generated power and inexpensive coal-generated power are exported from Alberta to BC. That is, BC will import wind-generated electricity from Alberta to meet domestic load, thereby storing water in hydro reservoirs that is then used to generate electricity at a future hour. Higher water levels in British Columbia lead to greater energy output from the province's hydroelectric generator and thereby also reduce coal imports from Alberta.

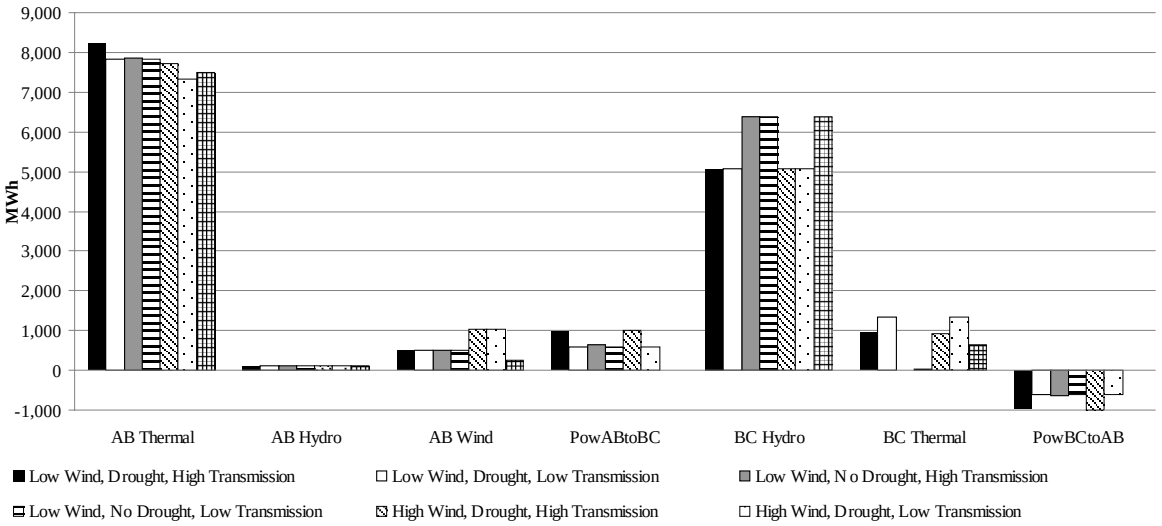

Figure 5.2: Electricity output by energy source, various model scenarios

Six scenarios are provided in Figure 5.2. Not surprisingly, Alberta thermal output is highest when wind output is low, water conditions are low and the capacity of the transmission intertie is at its greatest, thereby providing greater energy to British Columbia when the BC hydroelectric generators are least able to do so. Under drought conditions, transmission capacity is fully utilized with BC importing energy from Alberta. Drought increases thermal generation while transmission capacity determines its location, whether Alberta or BC.

Drought conditions may also exacerbate CO_2 emissions as increased transmission allows BC to import inexpensive coal-generated electricity from Alberta (Figure 5. 3). As wind energy is increased, the amount of coal-fired electricity needed by British Columbia falls. Thus, wind production in Alberta can decrease CO_2 emissions associated with meeting BC's internal load.

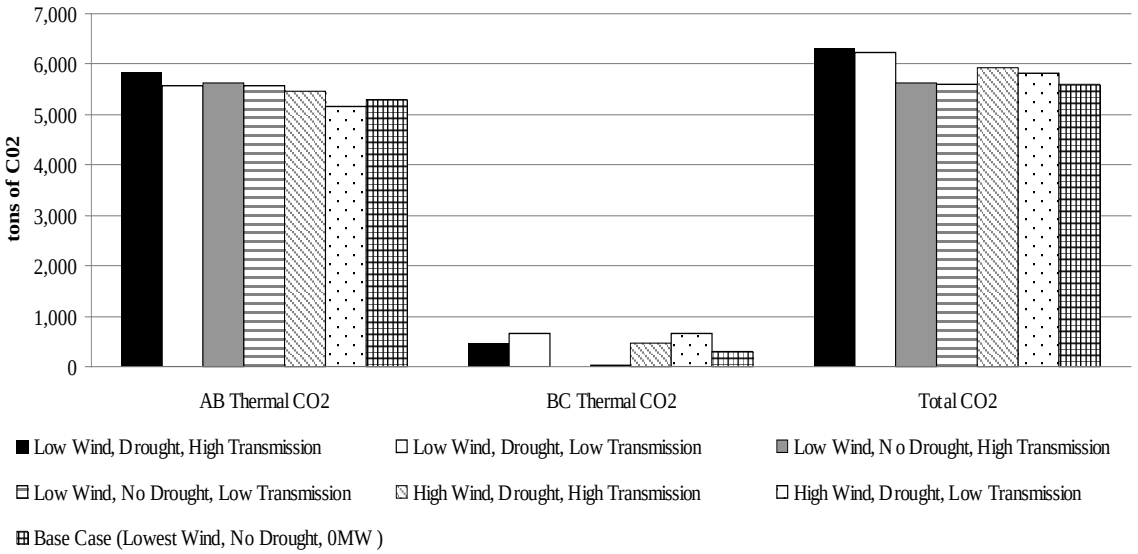

Figure 5.3: CO_2 emissions for Alberta and British Columbia

Carbon dioxide emissions by province are shown in Figure 5.3. The lowest CO_2 emissions occur when there is no drought and there is little transmission capacity between the two provinces. This restricts British Columbia's ability to import inexpensive but highly CO_2-intensive electricity from Alberta. BC uses its hydroelectric assets to create electricity and meet domestic demand, thereby keeping CO_2 emissions low. Increasing the capacity of the transmission intertie, while keeping water levels high and wind output low, increases CO_2 emissions, because BC will then, according to the model, import thermally-generated electricity from Alberta. The highest emission scenario occurs with low wind, drought and high transmission capacity between the provinces. With low wind, Alberta produces electricity with its thermal units and BC imports a large amount of this energy through the transmission intertie.

Lastly, we consider the climate benefits of integrating the BC and Alberta electricity grids to take advantage of BC's ability to store Alberta's wind-generated energy in an optimal fashion. To calculate the incremental cost of CO_{2e} emission reductions, we add the discounted annual transmission and wind turbine costs to the objective function. The total additional costs

depend on the amount of wind and transmission capacity used in each scenario. We then subtract off the base case costs, i.e., the objective function value with zero wind. The change in CO_{2e} is determined in the same fashion. First, CO_{2e} emissions under the various wind, water and transmission scenarios are calculated. We then subtract the base case CO_{2e} emissions resulting from running the model with zero installed wind capacity but differing water levels and transmission capacities. The change in total costs divided by the change in CO_{2e} for each scenario gives the incremental cost of CO_{2e} reductions in \$/tCO_{2e}. The costs of reducing CO_{2e} emissions are provided in Table 5.2. The variability in total CO_{2e} emissions results from the variation in wind output and any reduction in thermal generation.

There are five things to notice. First, if the cost of addressing climate change is in the neighbourhood of \$40-\$50 per tCO_{2e}, then wind energy is competitive with other means of reducing greenhouse gas emissions, even in a region where fossil fuels (coal and gas) and other sources of non-renewable energy (particularly hydro) are ubiquitous and therefore inexpensive.

Table 5.2: Incremental Cost of Reducing CO_2 Emissions (\$ per tCO_2e)

Item	1×Wind	2×Wind	4×Wind
600 MW Transmission Scenario			
Drought	\$44.94	\$49.63	\$52.97
Normal river inflow	\$53.35	\$53.49	\$54.75
1,200 MW Transmission Scenario			
Drought	\$19.55	\$30.69	\$42.97
Normal river inflow	\$56.24	\$36.72	\$55.96

Second, the ability to store wind energy in hydro reservoirs lowers the costs of reducing CO_2 emissions. This is indicated by the result that costs are reduced when the capacity of the intertie between the two provinces is increased. This is true even when the costs of increasing transmission capacity are taken into account.

Third, under drought conditions, wind energy and storage are even more important, as evidenced by the lower costs compared to 'normal' river inflows. This occurs because, with drought, wind tends to replace fossil-fuel generated electricity to a greater degree than under normal circumstances, simply because there is less water available to generate electricity and that electricity would otherwise have been generated using fossil fuels.

Fourth, as wind penetrates the grid, the costs of reducing a ton of CO_2 emissions increase. Under drought conditions and with ample ability to import wind energy from Alberta, the costs associated with CO_2 abatement are low. Initially, wind output effectively displaces thermally generated units of energy, so it is relatively inexpensive to reduce CO_2 emissions. However, with high wind output and normal water flows, the ability to further displace thermal generation (and reduce CO_2 emissions) becomes increasingly constrained, raising the cost of additional emissions abatement.

Finally, simply increasing transmission capacity will not lead to lower costs of reducing carbon dioxide emissions. In our model, increasing the capacity of the intertie between a power system with large wind generating capacity and one with large storage ability will lead to lower costs of mitigating CO_2 only if there is drought, but not under normal precipitation conditions.

5.5 Conclusions

One focus of climate change policy is the reduction of CO_2 emissions from the generation of electricity. Government policies in many jurisdictions encourage the development of wind capacity with the aim of lowering carbon dioxide emissions from thermal power generation. However, unless wind energy can somehow be stored, the variability inherent to wind-generated power can have a negative impact on the existing generation mix, causing thermal power plants to operate below their optimal levels and/or in standby mode for longer than necessary, thereby

increasing the costs of reducing CO_2 emissions above prices at which CO_2 offsets trade in markets. As demonstrated in this study, storage and increased transmission capacities can reduce such indirect costs.

Climate change may itself dramatically alter another zero-emission energy source, namely hydroelectric generation. In examining the impacts of drought on energy output, we find that, even with increases in wind energy output, thermal generation rises along with CO_2 emissions. Transmission capacity is vital in providing system security, because, in drought conditions without inter-provincial power flows, it is possible that demand in some region cannot be met. Although this model allows for an instantaneous increase in transmission capacity, with costs amortized over a 15 year period, in fact, the time for constructing new transmission can be between 8 – 10 years. Within that time frame, there are many factors that could provide an alternative to transmission investment including: demand side management, cost-effective storage technologies, natural gas supply and pipeline construction. At present, the strong growth in installed wind and solar capacity required to meet renewable portfolio standards must be connected to the grid. However, there is a considerable lag time between siting these intermittent generation resources and developing the transmission capacity to move the electricity to the load. Yet, as we have shown, increasing the capacity of an intertie does not guarantee that costs of reducing CO_2 emissions are also lowered.

Chapter 6: Conclusions

6.0 Introduction

The growth in variable energy technologies has created both difficulties and opportunities. With an increasing capacity to generate electricity from the wind, Alberta for example faces grid reliability issues resulting from the slow ramping characteristics of the province's predominantly thermal generation. In contrast, British Columbia, which is weakly linked to Alberta, has the potential to backstop the variability associated with Alberta's wind energy production. British Columbia's current supply configuration cannot meet domestic load and will require imports from adjacent markets or reliance on domestic thermal generation, both of which contravene the province's *Clean Energy Act*. Alberta will continue to see supply growth with the addition of wind production facilities and baseload natural gas generation. While a symbiotic relationship between the two provinces would seem beneficial (as indicated in Chapter 5), the future path of grid integration in the west is unclear. Impediments to transmission upgrades, provincial and state energy policies and the uncertainty associated with export markets could reduce the total benefits associated with complete western grid integration.

The purpose of this work was to provide policy conclusions and the focus was to develop straight forward models that give clear results. An evaluation of the impact of current provincial policies on the electric systems and estimates regarding the benefits of inter-provincial cooperation were provided. Managing resource development is a provincial responsibility; however, this research demonstrates that the individual optimization of provincial electric grids is inefficient. Carbon emissions and system costs could be reduced further if the two Western provinces would act to increase transmission capacity and jointly manage their electric generating resources.

In the following sections, we outline some of the academic and methodological contributions of the work, review the conclusions and provide some direction for future study.

6.1 Summary of Conclusions

Increasing Wind Penetration Reduces Grid Stability

The Alberta Electric System Operator forecasts continued strong growth in installed wind capacity – 1,575 MW by the end of 2012 and 2,500 MW by 2020 (AESO, 2010d; 2010b). Even at current levels, the system experiences grid reliability issues. Thermal generation in Alberta has an average ramp rate of 5 MW per minute or 50 MW in ten minutes. However, historical data show wind ramp down events of 174 MW in a ten minute interval, while the fastest wind ramp up events have wind generation increasing by 148 MW in ten minutes and these will increase over time. The disparity between wind ramps and the ramping speed of extant generation results in area control error (ACE) events or unscheduled flow on the Alberta-BC intertie. Our analysis in Chapter 3 shows that, with increasing wind capacities and given the slow system ramp rate associated with the thermal generating units, the system operator can expect an increased frequency of ACE events. The instability associated with high wind penetrations has increased the cost of contingency reserve provision and curtailed wind production. As wind penetration increases in Alberta an alternate means of ensuring grid reliability will become necessary.

Ummels et al. (2007) and Doherty, Denny and O'Malley (2004) amongst others have examined the unit commitment (UC) decision process, the economic dispatch (ED) protocol with deterministic or stochastic wind generation. The model presented in Chapter 3, appears at this time to be the only work wherein the UC and ED processes are jointly simulated over a one year period with stochastic wind in a thermally dependent and deregulated energy market. One of the

impacts of high wind penetrations in deregulated markets is that the resulting lower price erodes investment incentives. The results from the Alberta model show that energy prices fall with higher wind generation levels. At the same time, high wind jurisdictions require additional fast ramping generation from peaking plants to mirror wind ramps and maintain reliability. Peaking plants necessarily have a low capacity factor and as such, investors expect to recoup capital and other fixed costs that are not recovered during the plant's offline hours. Ironically, wind powered generation may be reducing the returns to peaking plant investors, economically damaging the very types of units that are required to make wind energy viable.

The eroded investment incentives can be seen in Alberta, but are also arising in other deregulated jurisdictions with high levels of intermittent generation. Texas has a deregulated electricity market with 11 GW of installed wind capacity. The Public Utilities Commission of Texas voted in favour of doubling the price cap in the region to $9,000/MWh by 2015 in an effort to encourage further investment in generating capacity as reliability margins are expected to fall below target levels (NERC, 2012). In the UK, the price depressing effect of wind and solar generation is eroding the creditworthiness of thermal generating companies. The overall impact of increased penetration of self-scheduled generation in deregulated jurisdictions is that capacity markets will need to be created to ensure grid reliability.

BC Policy Conundrum

In the BC *Clean Energy Act* (2012), the government of British Columbia set forth two main goals: energy self-sufficiency and a renewable portfolio standard (RPS) of 93 percent. Energy self-sufficiency includes a requirement for an additional 3,000 MWh of energy generation by 2016. The Act further specifies that the Burrard thermal generating unit may only be used for transmission support or in an emergency. The renewable portfolio standard requires

93 percent of domestic generation to come from clean or renewable energy sources.

As shown by the optimization model in Chapter 4, the provincial policy goals are incompatible. In disallowing both imports and thermal generation, and with end-of-simulation reservoir levels at 100 percent of their start volumes, there is no feasible solution because generation is insufficient to meet provincial demand. Energy self-sufficiency can only be achieved when the Burrard thermal unit is part of the generation portfolio and end-of-simulation reservoir volumes are substantially lower than their start values. However, utilizing the province's thermal generation contravenes the 93 percent RPS goal. As provincial load increases, especially given the strong growth in the oil/gas and mining sectors, the province's generation position will deteriorate with an increased dependence on electricity imports.

Effect of Drought on Inter-provincial Trade

The Alberta-BC model jointly optimizes a high hydro system with a heavily thermally dependent grid under various wind and water conditions. The novelty of this research is the valuation of incremental CO_2 emissions reductions when transmission capacity between two weakly linked but vast electric grids is improved. In the thermal/wind system different wind penetration levels are examined while two water inflow scenarios (drought, normal) impact the hydro-dominated grid. While the relationship between Alberta and BC's electric systems is unique in many ways, the results from this optimization model provide insight into the benefits of transmission infrastructure investment. In particular, the model highlights the advantages of linking low carbon resources in a thermally dependent grid given the opportunity to store energy either as water in hydro reservoirs or by way of another storage technology such as compressed air storage, batteries, or in plug-in electric vehicles.

Water conditions impact BC's ability to generate electricity. Setting aside the self-

sufficiency goal, BC will require more imported energy in low water years and that will likely come from Alberta as poor water conditions would also impact the hydro-dominated U.S. Pacific Northwest. When Alberta has sufficient wind generation and British Columbia faces drought conditions, and there is adequate transmission between the two jurisdictions, BC will import wind energy and store water for future electricity production. When wind generation in Alberta and water conditions in BC are simultaneously low, BC will import thermal generated electricity from Alberta. The carbon intensity of BC imports depends on which generating units actually provide energy to the grid. It is likely, however, that imports from Alberta will violate the RPS goal.

6.2 Grid Integration Benefits

Regarding first research question, we examined the impact of high wind penetrations on grid stability and found that, as installed wind capacity increased, area control error events rose by more than the growth in wind capacity. Long-term management of wind variability issues could include ancillary markets for wind ramping and firming services.

At present, the tie line between Alberta and British Columbia is scheduled two hours prior to the operational hour. This T-2 schedule precludes importers and exporters from responding to wind variation. Increasing the scheduling frequency or allowing for dynamic scheduling on the tie line would essentially provide Alberta with real-time energy to counterbalance the variation in wind generation. As Alberta's largest importer, British Columbia would be providing ramping and firming services to Alberta.

Even if intra-hour scheduling were achieved, available transfer capacity between the provinces remains an issue. At present, the 1,200 MW west-to-east total transfer capacity is limited to an average of 507 MW. If Alberta were to upgrade its provincial transmission grid, it

would be possible for the Alberta-British Columbia intertie to operate closer to its designed transfer capacity. Given that Alberta forecasts 2,500 MW of installed wind capacity by 2020, even the full transmission capability between the two provinces will be insufficient for ramping service provision.

While increasing the scheduling frequency of the tie line is under discussion, increasing the transmission capacity between the two provinces is not. From a revenue perspective, increasing imports from BC reduces the price received by conventional generators and importers both in the energy and the ancillary market. The ability artificially to restrict Alberta's supply may be why transmission capacity between the two provinces has not increased. British Columbia cannot increase intertie capacity without Alberta having solved its internal infrastructure issues first.

British Columbia faces two conflicting energy goals: self-sufficiency and a 93 percent renewable energy portfolio standard. As shown in Chapter 4, even in the near term British Columbia cannot meet domestic load with its current generating portfolio. The province will have to decide whether it would prefer to rely on imports from adjacent regions or renege on its decision not to use the natural gas-fired Burrard thermal generating station as a regular generating asset. If the provincial government relaxes the self-sufficiency goal, British Columbia could continue to import electricity from either Alberta or the United States, if sufficient excess energy exists and could be transmitted to BC.

Historically BC imports coal-fired power from Alberta during nighttime. BC stores its water and uses Alberta's excess supply to meet nighttime demand. During the day, when Alberta prices are higher, BC will meet domestic load with run-of-river energy or water stored in its reservoirs. The use of Alberta's coal-fired generation to meet BC demand has led to accusations

of resource shuffling – repackaging ‘dirty’ energy as a clean product – and claims that the 93 percent clean energy goal is not achieved at present.

As Alberta’s wind penetration increases, it may appear as though BC is purchasing wind generated electricity, in which case the Alberta-BC grids would be acting as a jointly managed wind storage unit, with BC storing wind in the form of water behind the dams.

Imports from the U.S. are equally complex. Mid Columbia is the largest adjacent U.S. market to British Columbia. The Pacific Northwest generation portfolio includes wind, large-scale hydro, gas, coal and nuclear units. Installed wind capacity in that region increased from zero to 4,421 MW in 14 years and there is an expectation of 5,000 MW of installed wind capacity by the end of 2013. Expecting to import electricity from the Pacific Northwest to fill BC’s energy gap could be problematic. Hydroelectric generation in both the Pacific Northwest and BC are influenced by the same snowpack conditions. Thus both regions experience high (or low) water conditions almost simultaneously and will be in essentially coincident net import or net export positions.

The best (but most unlikely) solution to both Alberta’s grid stability issues and BC’s energy supply shortage is the creation of a regional transmission organization (RTO). The RTO would oversee the operation of an integrated Western market and the transmission planning and performance within its confines. The benefits of an RTO include a simplified transmission rate structure, regional utilization of generating resources, a broader base of operating reserves, and increased scheduling efficiency of transmission as well as centralized transmission planning. By transferring the transmission decisions to a central authority, the welfare of both British Columbia and Alberta constituents could be improved.

6.3 Limitations and Future Research

In the preceding sections we briefly summarized the conclusions drawn from our three research questions. In this section, we provide an overview on some of the strengths and potential weaknesses in our methodologies.

In terms of the methodologies, the three models developed in the preceding chapters utilize differing time steps to balance the system This is a reflection of the focus of the investigation. In the Alberta model, the objective was to determine frequency and cost of both grid violations and contingency reserve dispatch. As contingency reserve providers have ten minutes to bring their units to their full offered volumes, the ten minute time step in the model was chosen to accurately simulate the process. In the BC optimization model, a ten minute time step was unnecessary; the daily balancing was sufficient to determine whether (or not) the province has the resources to meet its self-sufficiency goals and ascertain the import and thermal generation requirements. Ramp rates of generating units are not a concern in this hydro optimization as the existing assets have a ramp rate of 200 MW/min exceeding any load ramp. The Alberta-BC joint optimization model balances every hour essentially emulating the unit commitment decisions of the system operator With this time step, the hourly ramp rates of baseload thermal generators in Alberta were a binding constraint and the economic and carbon impacts of higher wind levels are not obscured by less frequent balancing.

Alberta Model

In Chapter 3, we examined the effects of increasing wind penetration on grid stability using a simulation model. The strength of this model is the realistic manner in which it replicates the actual balancing decisions made by the system operator. The model is populated by data from the Alberta electric system and includes actual ramp rates, offer prices and quantities submitted

by generators. We estimate the stability of the grid with increasing wind generation modeled using a mean–reverting stochastic process with an underlying Weibull distribution; the same scale and shape parameters are used in each of the simulations. Although we scale up wind output to reflect the higher installed wind capacity, we assume that the geographic concentration of Alberta's wind power facilities will persist as installed capacity increases, leaving the underlying distribution of wind generation unchanged.

One of the weaker points in the model is that we have implicitly assumed that wind generation will continue to be correlated despite increases in installed capacity as the mean reverting process was applied to a single wind generator. In modeling the provincial wind portfolio in this manner we assumed that any changes in wind speed would completely alter the output of that single generator. However, if wind power facilities were geographically dispersed, wind ramps in one region would not necessarily be coincident in a different region, mitigating the effects of wind speed changes. Although one might assume that increases in provincial wind capacity would become sufficiently geographically dispersed over time, there is no reason to believe that is the case in Alberta. Wind production facilities, both current and proposed, are almost exclusively located in the south of the province (AESO, 2012). However, a small portion of new generation will be located in the lower east central region. Future research would incorporate geographic dispersion into the provincial wind portfolio by adding wind power facilities in various regions with independent mean reverting processes. In modeling separate regions, and incorporating correlated wind profiles, we expect that the deleterious effects of wind ramps on grid stability may be reduced.

Another perceived weakness in the simulation is that the energy market merit order (EMMO) remains unchanged across the three different mitigation protocols we study. The

EMMO used in the simulation is the actual offer blocks of price and quantities submitted by generators to the Alberta Electric System Operator, given the short-term wind mitigation protocol that is currently used to manage wind ramping events. In changing the method by which the system operator dispatches from the merit order, generators would almost assuredly change their offer strategies. However, modeling the change in offer strategies is an extremely difficult task. In the case of over dispatch, we might expect an increasingly bifurcated supply stack. Recall that, in the over dispatch protocol, generators may only be in the merit order for a short period of time. By entering most of their capacity at $0/MWh, they secure dispatch, while any remaining capacity might be offered at $999.99 generating the maximum revenue for the short period when in merit. In future research we could estimate the EMMO with the province's minimum load offered in at $0/MWh and the remaining load at the province's price cap.

With respect to adding fast ramping generation to the supply stack, it is difficult to determine what the offer strategy of additional generators would be as the electricity market could be considered a repeated game in which 102 generators are determining and playing strategies 8,760 times per year. We could postulate that new entrants would enter their available peaking capacity at a price that would cover annual fixed and variable costs, given the estimated number of hours and volume required.

BC Self Sufficiency Model

In Chapter 4, we answer the question of whether or not British Columbia can be self-sufficient given the current configuration of its generating assets. This work optimizes the hydroelectric generating assets in two separate river basins, each with independent reservoir storage and downstream run-of-river facilities. The effect of reservoir levels on head height (and therefore generating capability) of the province's two largest power stations is considered. The

objective function in our model is to maximize revenue given the domestic value of generation and the constant price of imports and exports in both the Alberta and U.S. markets.

In reality the prices in both Alberta and the Pacific Northwest change hourly. In further research, the dynamics of BC's adjacent markets would be included, endogenizing the price of electricity. The deregulated nature of Alberta's electricity market provides transparency into its operations. However, the fundamental drivers of the Pacific Northwest power markets are not well studied. Given the dramatic increase in wind energy that is expected in that region (doubling the existing installed capacity of 3,000 MW by 2013), combined with the complexities associated with the California electricity market, a more thorough understanding of the fundamentals affecting the Western electric grid would be worthwhile. Adding the dynamics of Alberta and the Pacific Northwest to our BC model would improve its predictive power and could help guide provincial energy policy with respect to the *Clean Energy Act*.

Drought Model

Our drought model, presented in Chapter 5, describes the effects of wind and water changes on generation and CO_2 emissions in Alberta and British Columbia given differing transmission capacities between the two regions. The linear programming model minimizes the total cost of meeting demand in each region, given the operating, maintenance and fuel costs of the individual province's generating assets. We add wind generation to the Alberta system and reduce water availability in BC's hydroelectric system based on historical drought conditions.

One of the simplifications we created when modeling the two systems was to allow both drought and wind conditions to be independent, which may not be the case. Low wind conditions may be associated with low precipitation levels; however, an examination of current literature indicates a dearth of study in this area. Further model modifications would incorporate

correlations between water and wind conditions.

Low water conditions also impact thermal generators. In Canada, 64 percent of fresh groundwater withdrawals are for use in thermal generation (Natural Resources Canada, 2004). As the Alberta portfolio includes some hydroelectric facilities and utilizes both ground and surface water in thermal generation, the total energy supply in that province may also be impacted by drought. Estimating the effects of adverse water conditions on Alberta's thermal generating capacity could be incorporated into future research.

Currently our drought model examines only the relationship between Alberta and British Columbia. A more complete model would include interconnections with the Pacific Northwest, as described in the preceding section. Drought conditions that also adversely impact wind speeds will dramatically alter the supply drivers in the Pacific Northwest given the region's strong growth in wind capacity coupled with its heavily hydroelectric dominated asset base. When Alberta, British Columbia and the Pacific Northwest grids are linked via transmission lines, drought conditions that reduce the available electricity supply in BC and the Pacific Northwest will likely be compensated by increasing electricity production in Alberta, presuming sufficient intertie capacity. Whether the additional energy supply can be replaced by regional wind or thermal generators is an issue worth investigation; and, when wind and thermal generation are used to offset reductions in hydroelectric generation, the quantity of CO_2 emissions in the region is influenced by the relative extent to which the two technologies are utilized to produce power. Adding the dynamics of the Pacific Northwest electricity markets into our model will provide better insight into the impacts of increased wind and transmission capacity on CO_2 emissions from electricity generation in the region. Clearly, it will be difficult to target any future level of CO_2 emissions when wind and water availability are uncertain.

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