Integration of Wind Power in Deregulated Power Systems

by

Hugh Scorah
BA, University of Victoria, 2008

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Abstract

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This thesis investigates the impact of integrating wind power into deregulated power systems. It includes a discussion of the history of deregulation and the development of Independent System Operators and Regional Transmission Operators and their role in managing deregulated power systems. A linear algebra optimization model is used to explore the impact of wind power on the operation of the BC and Alberta power systems. The model is used to evaluate the costs and benefits of reducing carbon emissions by adjusting transmission size concurrently with wind integration as well as the value of BC Hydro's storage dams. Both drought and normal water year scenarios are considered.

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Dedication

To the surgeons and doctors who keep putting me back together again after I fall apart and my wife who steers me clear of trouble.

Chapter 1: Introduction

When it comes to serving the needs of the power system, the wind and sun have a habit of forgetting to put customers first. The wind will blow strong and then relax or disappear altogether when it is needed most, leaving the power system operators scrambling to find generation that can quickly replace the missing power. Generators will be moved away from their efficient operating points, will suffer more mechanical stress than usual, and more capacity will have to put on stand-by to handle the additional variability caused by increasing deployment of wind energy. Other times, late at night when only the big lumbering base-load generators are churning away, the wind will pick up producing power that no one needs or wants, and it will have to be dumped somewhere, often resulting in market prices that force the base-load generators to operate at a loss. All of this costs the consumer.

Despite this, electricity jurisdictions around the globe are struggling to deal with transmission interconnection queues that are overwhelmed with applications to bring substantial quantities of intermittent renewable energy onto electricity grids. In places like Ontario and New York, the wind power capacity that is expected to be constructed in the near future represents up to 30% of existing generation capacity. All of this is driven by government policies to mitigate the effects of anthropogenic climate change. Fossil fuels are cheap, have a high energy density, are easy to transport and store, and have served as a reliable energy source in the power system for well over a century. Unfortunately, fossil fuels used in the production of electricity also account for nearly one third of human caused CO_2 (IPCC, 2007) meaning that a reduction in greenhouse gas emissions must necessarily require a decrease in our use of fossil fuels for electricity production. As a result we lose the benefits associated with the convenience of fossil fuels and must manage the difficulties associated with carbon-free sources of energy.

This thesis explores the integration of wind power as an intermittent renewable resource used to displace fossil-fuel powered generators in the context of the Alberta and British Columbia power systems. In particular I look at the effectiveness of upgrades to transmission to aid in the integration of wind power as well as the effectiveness of using storage to absorb excess wind at put it to use in time periods where it is more valuable. Self-sufficiency in electricity in British Columbia, a contemporary political issue, is also addressed

Climate Change: Key Driver of Renewable Energy Development

In the 2007 synthesis report from the Intergovernmental Panel on Climate Change (IPCC), the authors report that the warming trend recorded in the period 1956 - 2005 was nearly double that of the period 1906 – 1955. Glaciers and snow packs are disappearing and it appears statistically significant that hot days and nights have become more frequent and cold temperatures and frosts have become less frequent (IPCC, 2007). In addition to the recorded changes in weather, there is also evidence that both land and water ecosystems are being affected by changes in the climate. The report also concludes that the greenhouse gas emissions from human industry are significant contributors to changes in the climate and ecosystems, noting that the amount of carbon dioxide and methane in the atmosphere is the highest it has been in 650,000 years.

Less certain than the current changes or their causes are the future implications of climate change. The IPCC expects increasing sea levels for centuries into the future, increased drought and desertification in equatorial regions, and substantial warming near the poles (IPCC, 2007). In equatorial regions, this is likely to represent challenges for the production of food, access to water, and public health. Migrations from coastal regions are a possibility as sea levels rise, while agriculture in the Northern Hemisphere may actually get a boost from increased rainfall and more moderate winters.

The projected changes are certainly significant enough to alter the growth paths of economies around the world. Maintaining standards of living in the developed world and enabling improvements in developing countries will require a change from the status quo. A key part of this change must be a change in the way that we produce and consume the energy used to power modern industry.

Wind as a Replacement for Fossil-fuel Generation

Renewable energy can be obtained from the wind, the waves and the tides, from the sun via photovoltaic cells or solar thermal plants, from geothermal plants and small hydroelectric dams, and from the combustion of bio-fuels. Of these technologies, wind power has dominated the development of renewable energy. As of 2007, wind power had a global installed capacity of 95 GW, about 40% of total installed renewables and more than any other source (REN 21, 2008).

The relative attractiveness of wind can be attributed to the fact that it is a mature technology with low costs and an abundance of potential development sites. The technology has been under commercial development since the early 1980s when costs were upwards of $0.80/kWh (American Wind Energy Association, 2005). Since then costs have come down to range from $0.05-0.08/kWh for on-shore wind developments and from $0.08-0.12/kWh for off-shore wind developments (REN 21, 2008). This makes on-shore wind power nearly competitive with coal generation and cheaper than combined-cycle natural gas generation. Like all renewable energy, wind is not subject to the volatility of global energy markets, which have a significant impact on the price of electricity because of electricity's dependence on fossil fuels. As already mentioned, wind is easier to site than renewables such as small hydro-electric and geothermal plants that require specific geological formations to be successful.

Despite all of these benefits, wind power suffers from a couple of major drawbacks that make its integration into the power system difficult. The first is the fact that the wind does not blow steadily all the time and can be highly variable at times, forcing other generators to pick up load as the wind dies down or to back off when the wind picks up. This behaviour can wreak havoc with electricity prices in the short term and shorten the life of thermal generating infrastructure over the long term.

The second drawback is the uncertainty of wind availability and wind speeds. In deregulated power markets, a great deal of the planning for operation happens a day beforehand. Forecasts are made of the wind power output, but, like all forecasts, they are inevitably wrong. Similar to the problems caused by variability, uncertainty requires more back-up generation to account for unexpected second-to-second changes in the balance of generation and demand. Using generation to manage these second-to-second changes often means pulling them off their efficient operating points and running them over a wider range of output that shortens the life of the equipment. If a power system is lucky enough to have hydroelectric resources, it is often the case that the dam reservoirs are only large enough to hold water for a few hours. If there is substantial intermittent renewable capacity together with these run-of-river hydroelectric plants the hydroelectric plants can be forced to waste water. This happens during low load periods when there is excess wind in the system and no other generators are able to be dispatch down, in this scenario the water behind the dam will be spilled. One renewable generator is offsetting the other.

To prevent these undesirable outcomes, it would useful to have a means of storing wind energy so that its output can be smoothed throughout the day. Grid-scale storage technologies under development include flywheels, batteries, compressed air energy storage, and, more recently, ultra-capacitors. Although NGK Insulators has been making large batteries to forestall sub-station upgrades in Japan for over a decade (Energy Storage News, 2009), and they have been used more recently in tests in California (United States Department of Energy, 2010), they are not yet cost effective for the purposes of smoothing the output of renewable energy sources.

An alternative to these more commonly discussed forms of storage is the use of large-scale hydroelectric storage dams to smooth the output of wind power. Hydroelectric power with storage is an ideal foil to the variability of wind plants. Hydroelectric generators are able to change output very quickly to follow changes in output. Electricity produced beyond the needs of the grid can be stored simply in the form of potential energy by allowing the water to back up behind the dam.

Much of the research described in this thesis explores the costs and benefits of using hydroelectric storage as an aid to the integration of wind energy in the context of the British Columbia and Alberta power systems. In the next chapter, I will discuss some of the deregulated power markets in North America and some of their recent experience with intermittent renewable energy. In the third chapter, I will describe the existing literature on the integration of wind energy and will outline the model that I have developed to analyze wind integration. The value of British Columbia’s hydroelectric storage is discussed in Chapter 4 in light of expanding wind capacity and costs of transmission upgrades. The model is extended in Chapter 5 to consider a drought scenario inspired by climate change modeling. In the final chapter, I discuss the more general lessons that can be taken from this research and suggest future research avenues.

Chapter 2: Wind in Deregulated Power Systems

There are two key differences between markets in deregulated power systems and other commodity markets. The first difference is the fact that electricity cannot be easily stored and must be consumed almost the instant that it is produced. In power systems with a complete absence of storage, this means that price arbitrage between hours is impossible. The second difference is the extreme lack of price elasticity on the demand side. This has largely been a function of government utility commissions mandating single prices for electricity that do not change with market conditions.

When retail prices are constant throughout the day, there is no incentive for the consumer to pay attention to the price of the commodity they are consuming. This is slowly changing in many jurisdictions where time-of-use rates are being introduced. These time-of-use rates usually have a two-step rate, one for ‘off-peak’ when the power system is not constrained and another for ‘on-peak’ when transmission lines are congested and demand must be met by expensive open-cycle gas generators. This rate structure is having the expected effect off reducing peak demand, but it will not help with the variations in real-time price that can be introduced by wind power variability.

The city of Chicago has moved towards a rate structure that is more conducive to efficient electricity markets and the integration of intermittent renewable energy. In Chicago, retail consumers face electricity prices that change with the dynamics of the wholesale market at the PJM Interconnection.[1] Real-time meters on homes measure not just the total kWh consumption of energy but record the hourly energy consumption, with consumers paying the real-time hourly price for electricity that is cleared in the PJM market on an hourly basis. Rates like this could go a long way to improving the integration of renewable energy. As production goes up thereby lowering market prices, consumers have an incentive to increase demand and, as the wind dies down, market prices would increase and consumers are incented to decrease demand. Unfortunately, even simple time-of-use rates where the price changes only once or twice a day are strongly resisted by consumers throughout the United States. This is mainly because they see the 'smart grids' required to monitor use as an extension of the state into the home and they have traditionally had no need to manage their energy use – doing laundry at 3:00 AM is a nuisance without upgrading your dryer to one that is 'smart grid enabled'. It is unlikely, therefore, that widespread use of Chicago-style rates will occur anytime soon.

Other means must be found to ease the integration of renewable energy into electricity grids. The following sections explore the ways in which some system operators in two Canadian deregulated power systems and California are using existing tools to achieve this goal.

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[1] The Pennsylvania-Jersey-Maryland Interconnection is the single largest electrical power system control area in the world. The interconnection covers all or part of 13 states and the District of Columbia in the United States and a summer peak load that can exceed 140,000 MW.

Independent System Operators (ISOs) and Regional Transmission Operators (RTOs)

The FERC Rulings

In the United States the Federal Energy Regulatory Commission (FERC) is primarily responsible for regulating the transmission of energy across state borders, either over electrical transmission lines or through pipelines in the form of oil and gas. Through its involvement in the management of the interconnected transmission system, the FERC has also become responsible for regulatory oversight of the deregulated electricity markets that have arisen over the past 30 years.

The post-World War II electricity system was organized into fragmented vertically integrated utilities that had just begun forming into power pools, such as the Southwest Power Pool, that were intended to aid the war effort (Southwest Power Pool, 2010). These utilities delivered generation, transmission and distribution services as a single package to customers and traded power only occasionally under restrictive agreements. Throughout the 1960s, load growth spurred the construction of large base-load facilities with significant returns to scale. Near the end of the decade this trend exhausted itself and the capital and maintenance costs associated with large nuclear and coal generation were driving the cost of electricity higher than ever before just as the oil crisis of the 1970s arrived.

In light of spiking fuel costs, the United States government decided to reduce its reliance on fossil fuels and, in the Public Utilities Regulatory Policies Act of 1978, they encouraged the development of renewable energy and cogeneration units and had them register as Qualified Facilities (QFs) under the Act (U.S. Code, 1978). The vertically integrated utilities were forced to purchase the power produced by these QFs. Other independent power producers (IPPs) started developing generation resources outside the scope of the Act, selling power to the utilities despite lack of protection. Alongside the QFs and IPPs, there arose electricity wholesalers and retailers who would purchase energy from these merchant generators and sell it to the highest bidder. Because the utilities still had total control of the transmission system, they were often able to exercise market power over the generators and retailers and demand unfair prices for the electricity in exchange for the use of their transmission lines.

Desiring to increase the competitiveness of the electricity markets in the U.S., Congress passed the Energy Policy Act in 1992. This Act encouraged the development of IPPs and wholesale power markets. It required transmission operators to provide a rate structure and details of physical constraints in the transmission system upon request by a wholesaler, who could then apply to FERC if a transmission operator was unwilling to offer service. This legislation required that an IPP file a claim at FERC every time it requested transmission service and the transmission operator refused to participate. After a dozen individual victories on point-to-point service, an IPP in Florida requested that the transmission operator provide network service equivalent to the service they provide the consumers in their own territory.[2] This resulted in ongoing litigation before FERC, which was not desirable.

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[2] Point-to-point service is the delivery of electricity from one bus in the network to another specific bus. Delivering power to another bus in the system would require another contract and possibly another rate structure. Network service is the delivery of electricity dynamically to any bus in the transmission system without the need to sign a separate contract for delivery under a common tariff.

It was clear that a more complete solution was required for the development of competitive electricity markets in the United States. Subsequently FERC ruled in Order No. 888 (Federal Energy Regulatory Commission, 1996) that all transmission operators must provide service of equivalent quality to what they would provide to their own customers at a common rate defined in an Open Access Transmission Tariff (OATT). This rate must then be available to all generators wishing to make use of the transmission system.

In addition to the requirement for the development of OATTs, FERC recommended that regional utilities and generators consider joining an Independent System Operator (ISO). ISOs do not own any assets in the system, are responsible for short reliability and long-term transmission planning, facilitate markets, monitor markets for the exercise of market power, and administer regional OATTs.

FERC Order No. 889 quickly followed, requiring that transmission operators separate their transmission and reliability functions from their marketing and wholesale divisions if they opt not to participate in an ISO organization. It also required that transmission operators develop an Open Access Same-Time Information System (OASIS) that would provide the details of the real-time physical state of the transmission system and make the details of all financial transactions in the system public for all wholesale market participants (Federal Energy Regulatory Commission, 1997). This order laid the foundations for the development of the infrastructure critical for competitive electricity markets.

Following Order Nos. 888 and 889, growth in generator capacity exploded resulting in considerable strain on the transmission system, which caused price spikes as congestion prevented the delivery of electricity to where it was demanded. It became clear that separating the development of generation and transmission was not sustainable. In FERC Order No. 2000, all utilities in the United States are forced to join a Regional Transmission Operator (RTO). An RTO could be an ISO or a transmission company that registers as an RTO and is governed by Order No. 2000. These RTOs are responsible for ensuring the reliability of the power system, operating ancillary service markets, administering the regional OATT and OASIS system, planning future transmission development, and coordinating with other RTOs (Federal Energy Regulatory Commission, 1999).

The Independent System Operators

Prior to Order No. 2000 ISOs had already started to form. In the United States, they appeared in California, New York, New England, the Midwest, and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). In Canada, similar organizations formed in Ontario and Alberta with their own OATTs. ISOs (and RTOs) have three primary responsibilities. The first is to ensure that all market participants have access to the transmission infrastructure in a competitive market environment under the regional OATTs. Utilities that joined an ISO or RTO became subject to the regional OATT.

The second responsibility is to maintain the reliability and stability of the power system within the guidelines established by the North American Electric Reliability Council (NERC). This involves ensuring voltage stability and the balance of generation and consumption in the seconds-to-minutes timeframe. It also involves planning for sufficient generation and transmission to meet demand up to 30 years into the future.

Finally, ISOs and RTOs are responsible for the development and operation of competitive markets for both energy and ancillary services. The energy markets are usually split into a day-ahead market and a real-time or hour-ahead market. The operators of the day-ahead market take forecasts of load for each hour to construct a demand curve and then accept bids from generators to provide energy to meet this demand. The real-time markets usually close an hour before the actual operating hour and exist to meet any remaining energy imbalances that could arise in the next hour because a generator awarded a contract in the day-ahead market has indicated it will be unable to meet its obligations or it is clear that the demand for power has been underestimated. As wind becomes more prevalent, the real-time markets for energy will become increasingly important because wind variability exacerbates energy imbalances in real-time operation.

Merit Order and Nodal Pricing

Energy prices are calculated by constructing a bid-stack or merit order out of the bids submitted by generators a day in advance. The merit order is the collection of capacity measured in megawatts (MW) and price pairs ($/MWh) sorted from the lowest price for capacity to the highest. All generators with capacity priced below the marginal price set by the capacity requirements determined by the load forecasts are awarded energy obligations for the next day.

The simple prices calculated in this fashion in early deregulated markets failed to provide the right incentives for new investments in infrastructure so, as of 2009, a new nodal pricing structure was adopted by all American ISOs and RTOs. In nodal pricing systems, the marginal clearing price differs from location to location (node to node on the grid), and is the sum of three components: the marginal energy price (MEP), the marginal congestion cost (MCC) and the marginal transmission loss (MTL).

- The MEP is the bid price submitted by the marginal generator in the merit order. Often generators will be forced out of merit order because the transmission lines have reached their carrying limits and less expensive electricity cannot be supplied to a load centre, so a more expensive generator closer to the load will be brought online that is not constrained by available transmission capacity.
- These additional costs are referred to as congestion costs and are identified separately as MCC.
- As the distance of a generator from a load centre grows, the amount of energy lost in transmission will increase linearly with the distance. This cost is also calculated and included as the MTL for the marginal generator.

The sum of these three components is referred to as the Locational Marginal Clearing Price and all generators at that nodal location receive the marginal price. This price system is designed to provide incentives for the development of locationally appropriate generation and transmission.

Nodal pricing systems are likely to play an important role in the integration of intermittent renewable energy. Nodal pricing provides a signal to transmission owners as to where new transmission infrastructure would best be developed to carry distant wind power to load centres. It also indentifies the most efficient generation capacity needed to meet energy imbalances caused by changing wind power output. The California ISO has identified the recent launch of their nodal pricing system as a key part of their effort to meet the Renewable Portfolio Standards set by the California government.

In addition to the energy markets, ISOs and RTOs are responsible for operating ancillary service markets. The three products usually found in ancillary service markets are regulation or balancing services, spinning reserve, and operating reserve. Regulation service is an obligation for a generator (or more recently load or energy storage device) to set aside a portion of its capacity for following imbalances in generation and load that arise between dispatch periods. Spinning reserve is an obligation of a generator to respond to extreme system conditions over a 10 or 30 minute period. Likewise, operating reserve exists to meet any losses in generation or transmission capacity over longer periods of time than served by spinning reserve. The impact on ancillary services is significant, particularly spinning reserves (Denny & O'Malley, 2007; EnerNex Corporation, 2007; Holttinen, 2005). Events like those in Texas on February 26, 2008 where nearly 1700 MW of wind power was lost over a three-hour period (Ela & Kirby, 2008) give a sense of the new pressures that large-scale integration of intermittent renewables will place on ancillary services.

In Canada, Alberta and Ontario have followed the ISO model of deregulating their power markets. The greatest difference between the Canadian electricity markets and those of the United States is the lack of a nodal pricing system. Instead, the provinces have opted for a province wide clearing price that all generators receive. This likely does not send the right signals about transmission constraints and generator capacity limits and could pose problems in the future, particularly in Ontario with its aggressive plans to increase the use of renewable energy in the province.

Wind in the Deregulated Power System

Deregulated power systems in North America face integration challenges from renewable energy to varying degrees. All of the ISOs in these regions are developing plans to smooth the transition to a power system where the outputs of the power plants can no longer be relied upon in the same way that they were in the past. Common to all of these plans is the implementation of centralized wind forecasting so that all market participants have common knowledge about output expectations, and improved transmission infrastructure so that the lowest cost reliable system resources can respond to rapid changes in output from renewable generation. The details of these plans differ from region to region and three are reviewed below.

Alberta Electric System Operator (AESO)

Of all the power systems discussed in this chapter, the Alberta grid has the greatest concentration of fossil fuel generation with 86% of their generation capacity supplied by coal and natural gas plants (see Table 1). The inflexibility that this would normally bring to a power system is ameliorated by the fact that the night time off-peak low demand averages about 83% of the afternoon peak. This high nighttime demand is a function of the northern tar sands and means that there is less of a morning ramp. A steeper ramp could pose serious problems with the increased integration of ramp and the prevalence of coal generation.

Table 1: The generation capacity mixes for the three deregulated power systems

	Alberta⁺	California*	Ontario**
Coal	**45%**	**18%**	**18%**
Gas	**41%**	**46%**	**24%**
Hydro	**7%**	**11%**	**22%**
Nuclear	**0%**	**15%**	**32%**
Other	**2%**	**8%**	**2%**
Wind	**5%**	**2%**	**3%**

NOTES:
⁺From 2010 (Alberta Electric System Operator, 2010)
*From 2008 (California Independent System Operator, 2009)
**From 2008 (Independent Electric System Operator)

Also of interest in the analysis that follows in Chapters 4 and 5 is the transmission links between Alberta and British Columbia. The two provinces have two 138 kV interties and one 500 kV intertie. The total potential Western Electricity Coordinating Council (WECC) rated capacity for export from Alberta to British Columbia is 1000MW and is 1200MW for import. Often, however, because of internal provincial constraints use of the line is restricted to 600MW for exports to BC and 760MW for imports (IPA Energy and Water Consulting, 2008).

The Alberta power system deregulated early relative to many other jurisdictions in North America. The Electric Utilities Act of 1996 mandated that all electricity in the province be sold through the Power Pool of Alberta (PPA), that the transmission lines be open to any registered member of the PPA in a non-discriminatory fashion, and that transmission lines would be operated by a Transmission Administrator. A later amendment in 2001 introduced deregulation of the retail electricity market so that consumers could purchase electricity from any of the registered utilities or energy retailers. In 2003 the province moved to consolidate the operations of the electricity market and the transmission system into the AESO, which also became responsible for long-term planning of transmission in the province (St. Amour, James, Shernofsky, & Brandt, 2006). With the exception of a voluntary 5.5% Renewable Portfolio Standard target for 2008, introduced by the Alberta government (Bradley, 2005), the government and the AESO maintain that no technology shall be favoured as the electricity market develops in Alberta. Despite the lack of extra incentives, the high electricity prices in Alberta have attracted approximately 630 MW of wind capacity as of 2010, with an additional 11,640 MW of capacity in the queue (Alberta Electric System Operator, 2010).

The AESO has identified four problems with wind that have been touched on above: (1) wind has the potential for very fast ramp speeds, (2) the output is uncertain and (3) variable, and (4) production is generally uncorrelated with load (Alberta Electric System Operator, 2007). The AESO expects that it will be able to use the existing market merit order for dispatch for slower changes and regulation services for shorter term changes, but has recommended two innovations to deal with growing generation from wind power (Alberta Electric System Operator, 2009).

The first of these innovations is the introduction of a ramp product into the market, with both generation and loads able to bid into the new market. Generators and consumers will be obligated to provide the ability to change their output over twenty minute periods to match the forecasted change in output from wind generation units. In studies commissioned by the AESO, it was noted that wind ramps often occur over several hours and that having a new ramp product would allow the AESO to distribute the ramp requirements over numerous resources, thus mitigating the impact this would have on any one resource in the system (Wang & Baker, 2005).

The second change to existing rules imposes both ramp and power limitations on a wind farm. These would limit the changes in output from a wind farm over certain periods and cap wind output if a substantial reduction in wind speed is forecasted.

Also mentioned in the AESO studies was a need for greater transmission infrastructure, both within the province and development of better interties with neighboring power systems. Internal strengthening of the Alberta transmission system would facilitate the wind generation developed in the south of the province to serve the substantial load in the north of the province associated with Edmonton and the more northerly tar sands. Therefore, the province has developed new south-north transmission capacity. Improvement of the interties, particularly with British Columbia, would offer considerable opportunity for the storage behind hydroelectric dams of energy captured by wind generators. Later chapters will focus on this possibility for Alberta.

California Independent System Operator (CAISO)

Despite working towards the goal of achieving 20% renewables by 2010, the California power system still obtained 64% of its electricity from coal and natural gas in 2008 (see Table 1) and only 10% from renewables. The remainder of California's electricity was obtained from hydroelectric and nuclear sources.

Of the three markets described here, California's load profile has the most extreme characteristics. The nighttime base load averages about 66% of the daytime peak. This incredible daily ramp is met by the substantial natural gas resources in the state. Such reliance on expensive natural gas generation opens the market up to considerable price volatility as the loss of a single generator could create a persistent energy imbalance that could require imports from outside or the use of generation higher on the merit order.

The California state government legislated the restructuring of the California power system in 1996, and in April 1998 a centralized market for power operated by the California ISO was opened; the three largest regulated utilities in California (PG&E, SCE and SDG&E) were forced to sell off their natural gas generation plants with the intention of decreasing potential market power. Although the generation section of the market was deregulated, retail rates continued to be set by the California Public Utilities Commission. When market prices for electricity shot up in June 2000 to average $143/MWh, it imposed massive losses on the utilities and caused bankruptcy in several cases. This appears to have been caused by a combination of inelastic demand, drought that reduced hydropower supply from the Pacific Northwest, and market gaming by a small number of marginal gas generators (Borenstein, 2002). In combination with a series of rolling blackouts, the extreme price volatility forced some rethinking of the market structure. As a result, the market in California has continued to evolve, culminating in the latest market changes in the CAISO Market Redesign and Technology Upgrade that has focused considerable attention on the integration of intermittent renewables that threaten to destabilize California electricity markets once again.

The California power system faces a greater renewable energy challenge than any other jurisdiction in North America. The California Renewable Portfolio Standard (RPS) requires that 20% of all energy consumed in the state be acquired from renewable sources by 2012 and 33% be acquired from renewable sources by 2020 (California Public Utilties

Commission, 2010). These aggressive deadlines for integrating renewables have inspired a complete redesign of California electricity markets. The most important changes to the market are the moves to a five minute dispatch of resources and to nodal instead of zonal prices. In its renewables report (California Independent System Operator, 2009), the CAISO emphasizes the importance of nodal pricing in identifying the most efficient means of dispatching system resources to deal with changes in the output of renewable energy.

One market innovation particular to California that has aided in the integration of renewable energy is CAISO's "Participating Intermittent Resources Program." Until the implementation of this program renewable power plant operators had little incentive to submit their e*n*ergy into the real-time market. Instead they would submit their bids to the day-ahead market, which provided more stable pricing but gave the ISO's operators trouble when the wind failed to arrive or was stronger than expected. Participation in the real-time market instead of the day-ahead market would decrease forecast error and improve the ability of the ISO's operators to account for changes in wind output.

To get the wind plant operators to participate in the real-time market, the CAISO offered a new settlement process. Normally, when a generator fails to provide the energy indicated, it must pay for that energy at the real-time price for that hour. This can be very costly as real-time prices during peak hours can frequently be hundreds or even thousands of dollars per MW. With the alternative settlement method, wind generators would be able to average their missed obligations over a month and pay the average price for the month. The trial of this method has been successful, but the CAISO noted that, as wind capacity grows and provides a greater fraction of the energy in the state, it will not be able to settle on this basis without negatively impacting the efficiency of the real-time market (California Independent System Operator, 2009). It is likely that wind operators will return to bidding into the day-ahead market if this incentive program is not available to them. This has been anticipated by the ISO and they have introduced scarcity pricing mechanisms in their market design. This will inflate the market price of energy and ancillary services when a wind or other system event results in the scarcity of energy or grid services. While this will likely provide the right incentives for resources in the California power system to be available to handle wind events, it will come at the cost of greater payments for energy by the consumer and increased volatility in the real-time market.

In addition to the market redesign, the California ISO has a strategy for the improvement of the technical integration of wind energy that is probably the most advanced in North America. The ISO has recommended that wind operators exercise greater control over their output. This would entail having ramp limiters to control ramp speed as wind picks up and power limitations when sharp downward moves are expected in the future. Energy storage devices, like batteries and flywheels, have also been identified as critical to the integration of renewables in California. These storage devices would operate at different time scales, providing ancillary services with several cycles a minute and storing energy at off-peak times for use at peak times that would involve only one or two cycles a day. These services will be critical to help with both the variability of renewable resources and the unfortunate increase in nighttime output that accompanies wind power plants. Similar to the storage initiative, the CAISO is expecting that the advanced metering infrastructure in California will improve and allow for real-time changes in retail electrical loads that will enable the shifting of loads from historical peak periods to off-peak times.

Independent Electric System Operator of Ontario (IESO)

The most interesting feature of the Ontario generation mix is its reliance on nuclear power. Nuclear generation accounts for 32% of capacity in the province and it is the least flexible type of generator (see Table 1). Recently this has had unusual consequences for price dynamics in IESO markets, where the price has gone negative because it is very expensive to ramp generators down and a disaster if they are turned off without prior preparation. In addition to nuclear generation, the province gets 22% of its power from legacy hydroelectric assets operated by Ontario Power Generation, a crown corporation independent from the IESO.

The loads in Ontario vary considerably more from night to day than in Alberta. The ratio of average nighttime base load to daytime peak is about 73% and meeting the daily ramp requires the use of the hydro assets at Niagara.

The Ontario power system was deregulated in 2002. Similar to the opening of the electricity market in California, deregulation resulted in a very volatile price environment. The sudden increases in electricity prices led to a political firestorm that brought in a new government to ‘fix’ the broken market. The new government created the Ontario Power Authority (OPA) that had the responsibility of dealing with system planning issues that would ensure system reliability and price stability in the long run, as well as encouraging conservation and developing Demand Response programs. The new Green Energy Act in

Ontario has also given the OPA the mandate to manage the feed-in-tariffs (FITs) for renewable energy in the province.

The current FIT in Ontario pays 13.5 cents/kWh for on-shore wind farms and 19 cents/kWh for off-shore wind farms (Ontario Power Authority, 2010). As a consequence of these incentives, the IESO now expects that they will have 3000 MW of wind capacity installed by 2015 and 4500 MW of wind by 2020 (Khan, 2008). Currently the IESO has about 1200 MW of installed wind capacity with a capacity factor of 28%.[3] This has exacerbated problems with pricing in market conditions where they have large quantities of base load generation and low nighttime loads (Independent Electric System Operator, 2009). For 351 hours in 2009, the price was negative partly as a result of excessive wind energy (Independent Electric System Operator, 2010). Currently, wind turbines are paid their FIT regardless of market conditions and there is no incentive for them to curtail output when market prices go negative. The Ontario taxpayer is always on the hook for these price situations because the generators must be paid to keep the lights on even if they are operating at a loss. In addition to negative prices, the increased need for regulation services as a result of higher wind penetrations requires a 4% increase in regulation procurement for 5000MW of installed wind capacity, and an 11% increase for 10,000MW of wind capacity (Van Zandt, et al., 2006). If the price of regulation services stays constant, this would amount to about $5 million in additional annual costs.

To overcome these problems, the IESO has started work on a plan to better integrate renewable energy into the market. The core of their plan is a centralized wind

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[3] The easiest way to calculate the capacity factor of any generator is to take the total kWh of energy produced by the generator in a year and divide it by the total number of kWh the generator can theoretically produce in a year (capacity in kW × 8760 hours).

forecasting service that will be started in the summer of 2010. This will allow the power system operators to mitigate their previous reliance on proprietary forecasts from wind operators and better manage their impact on the day-ahead and real-time markets. In their reliability report, the IESO discusses the importance of demand side management and the smart grid coupled with dynamic pricing at the retail level as a means to increase demand elasticity and handle some of the variability in wind output. However, it is unclear what steps will be taken by the IESO to achieve this (Independent Electric System Operator, 2010).

The IESO has also pointed out that integration of the Ontario market with those of surrounding ISOs is critical to the full integration of wind energy. This involves not only upgrading the transmission interties between markets but also the development of integrated market rules and greater coordination in operating protocols. Starting in the first quarter of 2011, Quebec Hydro and the New York ISO are expected to go to a five minute schedule on the tie-line between the two power systems (DeSocio, 2009). It would not be surprising to see developments like this between the IESO and its surrounding ISOs in the near future as the five minute dispatch could provide substantial market flexibility that is able to account for rapid fluctuations in the output of intermittent renewable generation similar to the ramp product proposed in Alberta.

Transmission and the Integration of Wind

Although the ISOs are developing innovative schemes to aid in the integration of renewables, all the strategies have the common goal of improving transmission infrastructure. Improved transmission can expand the markets available to wind power and improve the ability of fast moving generation to follow the changes in output from wind generators. In Alberta this has special significance, because better transmission interconnections with British Columbia not only expands the market for wind power and the sources of generation that can be used to balance changes in the wind power, it also allows for the use of British Columbia's storage dams to absorb excess wind energy. This integration of the two power systems could prevent the curtailment of wind energy when it is not demanded and reduce overall greenhouse gas emissions across the two provinces. Following a literature review, I explore the costs and benefits of expanding transmission capacity between Alberta and British Columbia to improve the integration of wind generators under a variety of scenarios.

Chapter 3: Modeling the Integration of Intermittent Wind

Literature Review

In the earliest review of the integration of intermittent renewable, Kahn (1979) pointed out that intermittent energy sources will be uncorrelated with load, and that the existing infrastructure may not be able to keep up with the ramps in output caused by wind and solar generation. While renewable technologies have matured since then and are far more prevalent, researchers continue to struggle to identify the true costs of integrating renewable energy into power systems. Modeling the costs of integration is one approach to identifying costs, and has generally been approached using either load duration curve models or mathematical programming methods.

Load duration curve models generally treat wind generated power as negative load. Simulated wind output is increased and the effects on infrastructure are estimated from the net-load series. These models generally assume that the wind power and load series are drawn from the same distribution resulting in an unrealistic estimate of the correlations between wind and load. The load duration curve models also give no sense of how existing resources are used to meet new net-load requirements or how infrastructure might change to adapt to increasing wind penetrations (Milligan, 1999). Although they provide an interesting first approximation, better modeling requires the use of mathematical programming methods.

Mathematical programming models require the assumption that the power system is being operated to minimize costs. An early example of this modeling approach is found in a study of the Quebec power system and the effects increased penetration have on the reserve capacity needed to deal with power system variability (Belanger & Gagnon, 2002). With wind representing as little as 10% of the Quebec system capacity, Belanger and Gagnon (2002) find that Quebec would have to increase the capacity of its hydroelectric resources to manage the wind variability.

A similar model of the Irish power system shows that increasing penetrations of wind resulted in increased requirements for ancillary services, the operation of conventional generation at sub-optimal capacities, increased cycling of conventional generation, a shortened life-span of the units, and an accelerated need for a reinforced transmission system. The threshold for positive net-benefits in this model occurs at approximately 20% penetration, above which net-benefits are negative (Denny & O'Malley, 2007).

Decarolis and Keith (2006) argue that one cannot assume that the infrastructure in the grid will remain constant as the penetration of wind increases. In their model, they allow the grid operator to choose the optimal technology mix and find that, with the increased use of Compressed Air Energy Storage and combined cycle gas units, the Midwest power system would be able to handle wind penetrations of up to 50% without negative side effects.. Unfortunately these models are unrealistic in practice as wind capacity is growing faster than the transmission infrastructure and generation capable of following fast ramps is not built to keep up with capacity largely because of ineffective long-term price signals in deregulated markets.

Another model looking at the use of hydroelectric storage in the Alberta power system compared the cost of increasing wind generation with the price of carbon credits traded on the European Climate Exchange (Benitez, Benitez and van Kooten, 2008). Three scenarios were evaluated in this model, one with no wind, and two with increasing quantities of wind replacing coal generation. Similar to Decarolis and Keith (2006), the model not only minimized costs but evaluated whether it was necessary to increase the capacity of gas units with peaking capabilities. The cost of reducing CO_2 emissions was estimated to be \$41-\$56 per tCO_2. In a another model of the Alberta electricity grid where the optimal generation mix is selected to account for the integration of wind, the cost of reducing greenhouse gas emissions is estimated at \$66/tCO_2 (Prescott & van Kooten, 2009).

Some models have been built to assess whether or not the total energy needs of a power system could be met with wind power alone. Czisch and Bernard (2001), using a load duration methodology, claim that 100% of Europe's energy needs could be met with wind power if catchment areas in Russia, Kazakhstan and Morocco were developed in addition to sites in Europe. The authors do not consider the cost of accomplishing this nor acknowledge the weaknesses of using load duration curve analysis. Prescott, van Kooten, and Zhu (2007) tackle a more manageable scenario in which the Vancouver Island power system is modeled using a constrained optimization model that minimizes cost. The authors find that, regardless of cost and the number of wind turbines, it is not possible to meet the needs of the Island solely with wind power – there are always hours in the year when there is insufficient wind blowing to meet power demand.

In another model of Vancouver Island, Maddaloni, Rowe and van Kooten (2008) test the effects of wind penetrations on transmission limits. When transmission constraints are included, more wind means higher costs for the other generators in the system and the increases in wind generation require upgrades to the transmission system. Wind penetrations greater than 20% result in negative net benefits.

Finally, in another use of their Vancouver Island model, Maddaloni, Rowe and van Kooten (2009) consider three different power systems; one predominantly hydroelectric, the others with an emphasis on nuclear and fossil fuels, respectively. The model shows that decreased fuel costs from increases in wind capacity are quickly overwhelmed by increasing capital costs.

Modeling Approach

The model described in this section draws inspiration and technical know-how from the models of Prescott et al. (2007), Benitez et al. (2007), and Prescott and van Kooten (2009). The Alberta power system is treated in greater detail and the model focuses on the transmission constraints and energy storage of the British Columbia network of hydro dams. Both the British Columbia and Alberta power systems are assumed to be run by cost minimizing organizations. Cost minimization is modeled as a linear programming problem, where the objective is to minimize variable cost subject to load and engineering limitations.

Total variable cost is a function of the operating and maintenance costs (OM_i), the fuel costs (FC_i) and the output in MWh ($Q_{i,t,p}$) for each generator i in province P. The optimal output is selected in every time period t to minimize the cost over one year (8760 hours). This is formalized in equation (1):

$$\text{(1)} \qquad \underset{Q_{i,t,p}}{Min} TC = \sum_{t=1}^{8760} \left[\sum_{i} \sum_{p} (OM_i + FC_i) Q_{i,t,p} \right], P = AB, BC$$

In every hour the demand for energy in both provinces must be satisfied separately. For each of the provinces (P), the total output from all the generators in the province must provide the energy consumed by loads ($L_{t,P}$), exports($X_{t,P}$), and the wasted renewables ($W_{t,P}$). Renewable energy is wasted when wind energy is produced and there is no load to absorb it when the fossil fuel generation is unable to ramp down. The load constraint is represented as:

$$\sum_{i}^{N_p} Q_{i,t,p} - L_{t,P} - X_{t,P} - W_{t,P} = 0, for\ all\ P = AB, BC; t = 1, \dots, T \tag{2}$$

In this constraint there are N_p generators in each province P, and exports are over the tie line between British Columbia and Alberta.

Because these power systems are modeled at an hourly resolution, I am unable to address the short term power imbalances caused by the variability in wind power, but I do model the potential energy imbalances caused by long wind ramps uncorrelated with load. In an electrical grid like Alberta where the bulk of the power is supplied by coal generation, it is possible that wind may ramp up during low load periods leaving the coal generators ‘stranded’ and unable to ramp down, especially with high penetrations of wind. During such instances, the wind power is dumped (into variable *W*) if it cannot be exported to British Columbia. In these scenarios, with high penetrations of wind, the size of the intertie can be critical to the amount of wind energy that is wasted.

The hydroelectric generators in this model are simplified by having a fixed head.[4] Introducing the realism of having a head that is a function of reservoir volume introduces a non-linearity that substantially increases solution times so the head is kept fixed in this

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[4] The head on a hydroelectric dam is measured as the vertical difference between the water intake and outtake.

model. The power output of each hydroelectric dam h at time t is described by the following equation:

$$Q_{t,h} = \eta_h \times g \times d \times F_{t,h} \times H_h \times 10^{-6} \tag{3}$$

where η_h is 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} is used to convert the output in watts to MW. By fixing head height, only flow is variable and linearity is maintained.

The volumes in the reservoirs are managed to ensure that minimum river flow requirements are met for environmental reasons and the maximum storage limits are not reached. The reservoir volumes are described by the following equations:

$$V_{h,t} = V_{h,t-1} + I_{h,t} - F_{h,t} - S_{h,t} \tag{4}$$

where $V_{h,t}$ is the volume of water in the reservoir of dam h at time t, $I_{h,t}$ is the inflow of water into the reservoir, $F_{h,t}$ is the amount of water taken into the penstock, and $S_{h,t}$ is the amount of water spilled if there is insufficient capacity to store the water.

The water flowing into the penstock and the water that is spilled must exceed required minimum flow of the river, $\underline{F_h}$.

$$F_{h,t} + S_{h,t} \geq \underline{F_h} \tag{5}$$

Additionally, the maximum storage limit $\overline{V_h}$ must be respected:

$$V_{h,t} \leq \overline{V_h} \tag{6}$$

All the generation units in the model must respect their minimum and maximum output constraints, $\underline{Q_i}$ and $\overline{Q_i}$:

$$Q_{i,t} \leq \overline{Q_i} \tag{7}$$

And

$$Q_{i,t} \geq \underline{Q_i} \tag{8}$$

For Alberta, the generation units are grouped by fuel type. No attempt is made to model individual generators. In the generator aggregates, the minimum output represents the sum of all the generator minimums. Particularly with coal generation, this is a reasonable assumption as these generators are unable to shut down for the night and restart for the morning ramp.

Generators are also constrained by their ramp rates. Although this model does not allow for the modeling of intra-hour constraints, the energy imbalances caused by large changes in wind output are captured by the hourly ramp rates in this model and they are frequently constraining as the wind output is scaled up. The ramp up rate is specified as R_i and the ramp down rate as D_i:

$$Q_{i,t} - Q_{i,t-1} \leq R_i \tag{9}$$

$$Q_{i,t-1} - Q_{i,t} \leq D_i \tag{10}$$

In addition to the generators, the transmission system is treated as if there were only two buses – one in Alberta, the other in BC. Between the British Columbia and Alberta load centres is a single transmission line whose size is varied over a wide range to assess the costs and benefits of improving the provincial intertie and the integration of wind power in the provinces. The transmission line is modeled without losses and each province faces a maximum export constraint. Because Alberta has internal provincial constraints they may import less than they are able to export (Alberta Electric System Operator, 2010) and this is reflected in the values chosen for the maximum export for

British Columbia and Alberta, $\overline{EX_{BC}}$ and $\overline{EX_{AB}}$, respectively. The transmission constraints are represented by the following equations:

$$EX_{BC,t} + EX_{AB,t} = 0 \tag{11}$$

$$EX_{BC,t} \leq \overline{EX_{BC}} \tag{12}$$

$$EX_{AB,t} \leq \overline{EX_{AB}} \tag{13}$$

where equation (11) requires that the exports from one province must equal the imports of the other province.

Tools used in the development of this model include excel, Python, and a linked MATLAB-GAMS environment (Wong, 2009). The MATLAB and GAMS code can be found in Appendix B.

Chapter 4: Energy Storage, Intermittent Renewables, and Drought

In the context of the electric power system, energy is a very difficult thing to store. Despite considerable time and investment, adoption of batteries, flywheels and compressed air energy storage are still in the early stages. The reality in most power systems is that electricity, once generated, must be consumed the instant that it is produced. One exception concerns the use of hydroelectric storage dams. These dams are common in British Columbia and Quebec, and can effectively store energy by allowing river inflow to accumulate in the reservoirs behind the dam when the energy available from renewables plus unavoidable generation from extant generators exceeds demand.

Unfortunately, sites appropriate for the development of hydroelectric storage dams are constrained by geography. The best sites were developed in the post-World War II period and the potential for expansion is limited. Even worse, climate change increases the likelihood of drought. Climate change induced droughts would result in decreased river flow and may increase water-use conflicts between competing uses such as power generation, agriculture and fisheries. These kinds of conflicts could make hydroelectric storage of intermittent renewables less attractive.

This chapter uses the model developed in Chapter 3 to explore the issues of energy storage in the context of the interconnected British Columbia and Alberta power systems. Up to now the development of intermittent renewables in these power systems has largely taken place in southern Alberta where they have installed wind generating stations with a nameplate capacity of nearly 600 MW. As this capacity grows one of the challenges in using British Columbia’s storage dams as a resource for capturing other renewable energy is the capacity of the transmission interconnection between the two power systems. I use the model developed in Chapter 3 to explore the costs and benefits of expanding transmission capacity while the capacity for wind production grows and British Columbia suffers through different drought scenarios.

Data

The approximately 11,000 MW of generation capacity in the BC Hydro system has been modeled constituting seven components. This includes five hydroelectric dam aggregations including Gordon M. Shrum, Revelstoke Dam, Mica Dam, the Peace Canyon, and remaining hydro. The first four of these are modeled as having storage reservoirs. The remaining generation is included in two categories, Burrard Thermal and remaining thermal generation.

The Alberta power system has been modeled as eight different aggregates. These include three types of generation that are taken as self-scheduled. That is, the generation output has been taken as given and the system operator has no control over the output. These three categories are (1) wind, (2) biomass and (3) cogeneration units that also provide heat to the tar sands in northern Alberta. The remainder of the generation can be dispatched by the system operator and they include the (4) Big Horn and (5) Brazeau hydroelectric dams, (6) coal and (7) combined cycle gas generation and, finally, (8) gas peaking units.

The real interties between Alberta and British Columbia consist of two 138 kV lines and one 500 kV line. Here they are modeled as a single line between the provinces and the megawatt capacity of these lines is changed under different scenarios to understand the impact of different transmission availabilities on the integration of increasing wind power capacities in southern Alberta. Although this transmission line is rated for 1000MW export from Alberta to BC and 1200MW import to Alberta other operating constraints require that exports be limited to 600MW and imports be limited to 760MW (IPA Energy and Water Consulting, COWI A/S, SGA Energy, 2008). In addition to this scenario, a zero capacity scenario is considered where the two power systems are isolated and a scenario where the internal Alberta constraints are lifted so that the interconnection between the two provinces can operate at full capacity.

Data for historical loads was obtained from the AESO and BC Hydro, while river flow data was obtained from Environment Canada.[5]

Modeling the Wind

The other two forms of self-scheduled generation (biomass and co-gen) are included in the model using historical data; but because wind capacity is scaled in a number of scenarios, it is necessary to take a more complex approach. Several approaches have been suggested for the modeling of the wind in the renewable integration literature (Soder & Holtinnen, 2008). These methodologies include physically modeling the wind speeds and how they interact with a field of wind mills (Dua, Manwell, & McGowan, 2008) or shifting and scaling previously observed wind plant outputs (Maddaloni, Rowe, & van Kooten, 2009). An alternative means of synthesizing wind outputs takes historical data and models some of its time dependent characteristics and uses these statistics to generate new data using stochastic processes (MacCormack,

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[5] A table with more details on the nature and source of the data used in the model can be found in Appendix A.

Zareipour, & Rosehart, 2008). If historical wind speed data are difficult to obtain or the computational complexity of modeling the physical wind farms is too great for the purposes of the model, this approach provides a superior means of scaling wind profiles for modeling future capacity scenarios.

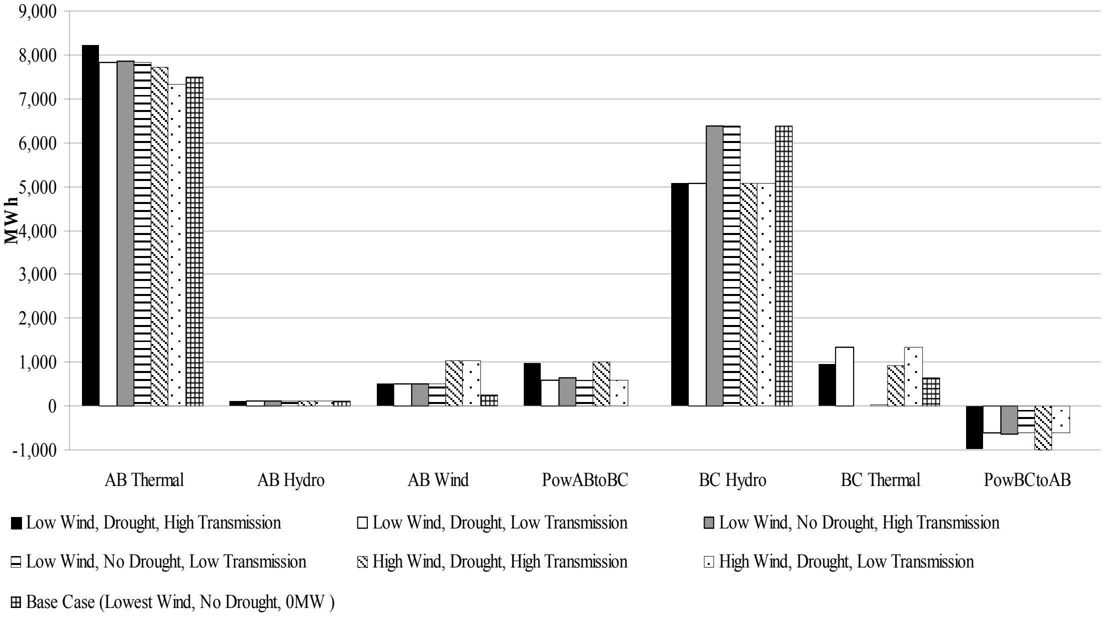
To generate the new wind profiles, five-minute wind data from the AESO are used for the year 2008. The year's average is taken and subtracted from the series, leaving a year's worth of residuals. The residuals are separated into monthly values and averages are taken again and subtracted to give a new residual series. This is repeated for the days and hours in the year until there is a final residual series remaining. A distribution is fitted to these remaining residuals and random values are drawn from the distribution. These are then added back to the means for the hour, day, month and year to produce the new synthesized series. To model a doubling of capacity, the mean values are multiplied by two and the random series is added back in. The values of the series in this process must be constrained to be greater than zero.

Results

To model the effects of different transmission constraints and drought on the integration of renewables, thirteen different scenarios are considered. First wind is considered at existing levels and then it is doubled and then quadrupled. For each of these scenarios the transmission system is tested with existing export capacity at 600MW and again at 1200MW. Finally, for every wind and transmission scenario the river flows are modeled under normal and drought conditions. The results of these runs are shown in Figure 1.

The most recent drought in Western Canada occurred in 2001-2002. During this time river flows peaked at 37.5% of the normal flow. These extreme low water conditions coincided with the California energy crisis. It is possible that the low water-flow conditions in the Bonneville Power Authority System at this time may have contributed to the high prices.[6] Scenarios like this raise concerns about the relationship between drought and energy security.

Figure 1: Electricity Output by Energy Source, Alberta and British Columbia under the different wind, transmission and drought scenarios. The Alberta fossil fuel generation is displaced as wind generation increases.



Water flow that is 37.5% of average river flow was used throughout as the drought scenario. Initial runs of the model had reservoirs start out at 37.5% and the model failed to solve no matter how much wind generation was made available or how large the

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[6] The Bonneville Power Authority manages and coordinates transmission and wholesale power markets in the United States Pacific Northwest. The California ISO frequently imports electricity from the region which has a great deal of hydroelectric generation.

transmission capacity. Although the model precludes the possibility of importing electricity from the United States, this result suggests that an extended drought over 5-10 years would have severe implications for the energy security of British Columbia. Under this scenario, the goals of electricity self-sufficiency outlined in the 2010 Clean Energy Act would not be obtainable (2010 Legislative Session, 2010).

For the model to solve, the initial reservoir capacity had to be set to 60% for drought conditions river flows at 37.5% of normal. With initial conditions that allow the model to be solved British Columbia starts to import the energy it needs from Alberta. The impacts of changing the transmission and wind power capacities have noticeable impacts on fossil fuel generation in Alberta, the use of BC Hydro's Burrard Thermal generation unit, availability of BC hydroelectric facilities and the use of the BC-Alberta intertie. These are treated in turn with partial summary in Figure 1.

In this model, increasing the capacity of wind generation has the desired effect of reducing the output of Alberta's coal and natural gas generators. As expected, increasing the available transmission capacity improves upon the reduction of fossil fuel generated electricity. This reduction occurs because excess wind power is imported into BC where it is used and water that would have been used for power generation is stored behind the dams. This electricity can be generated later when the wind is unavailable displacing the fossil fuel generators which have a higher marginal cost of operation. The greater the capacity of the interconnection the greater the ability of wind power to be imported into BC.

Figure 2 considers the scenarios in more detail. It can be seen that generation from Alberta fossil fuel generators is greatest when there is the least amount of wind generation installed and the drought conditions are in effect. With reduced hydroelectric capacity in BC and no wind energy to absorb, the energy deficit in BC must be made up with fossil fuel generation from Alberta. Increasing the transmission capacity in this scenario only increases the amount of energy imported from Alberta as BC turns off its own thermal generating assets in favour of the cheaper resources available in Alberta. This will also have the effect of increasing CO_2 emissions as natural gas generation in BC is displaced by dirtier coal generation in Alberta. Increasing wind generation again decreases aggregate CO_2 emissions in the two power systems, as expected.

Figure 2: CO_2 Emission for Alberta and British Columbia under different wind, drought and transmission scenarios. Increases in wind capacity decreases emissions.

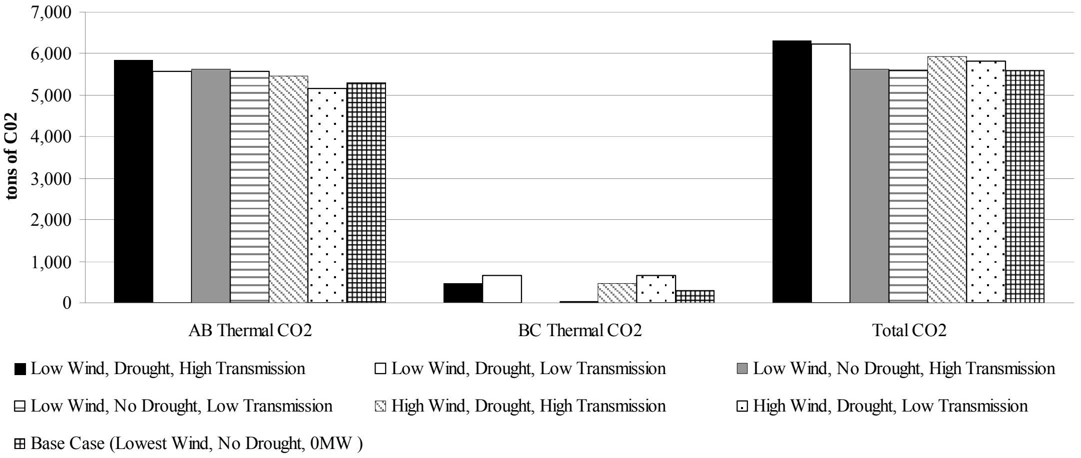

Figure 2 gives the emissions for Alberta, BC and the total for both systems. Keeping everything else constant, an increase in transmission capacity will increase emissions. This occurs because inexpensive coal generation displaces the more costly natural gas generation capacity in BC. The drought scenario also increases the production of CO_2 emissions as BC Hydro's generators are unable to meet the energy needs of the province and the cheap and dirty coal generation is imported to fill the gap. When wind capacity is increased, CO_2 emissions are decreased.

After observing that increasing wind capacity does in fact reduce CO_2 emissions in the two provinces, it is interesting ask whether or not this is a cost-effective greenhouse gas mitigation strategy. Table 2 shows the incremental costs of reducing CO_2 emissions in \$ per t CO_{2e}. The results of this model suggest that wind electricity in the Alberta-BC interconnection is a cost effective means of reducing emissions with incremental costs in the range of \$20-55 per t CO_{2e}. This result may be surprising given the prevalence of existing hydroelectric generation in the BC Hydro system as one might be led to believe that incremental improvements in a system like this could be quite expensive. It makes more sense in the context of the discussion above where we think of the hydroelectric dams as storage capacity. Increasing the transmission capacity between the two provinces provides greater access to these storage resources and predictably lowers emissions.

Table 2: Incremental Cost of Reducing CO_2 Emissions (\$ per t CO_{2e}) under the different wind, drought, and transmission scenarios.

	1×Wind	2×Wind	4×Wind
600MW Transmission Scenario			
Drought	**\$44.94**	**\$49.63**	**\$52.97**
Normal river inflow	**\$53.35**	**\$53.49**	**\$54.75**
1200MW Transmission Scenario			
Drought	**\$19.55**	**\$30.69**	**\$42.97**
Normal river inflow	**\$56.24**	**\$36.72**	**\$55.96**

The data also show that, under drought conditions, greater wind capacity and the ability of the dams to store energy becomes even more valuable. This can be seen in the lower costs between the drought and normal river flow scenarios. These lower costs appear because BC Hydro can use wind power in the off-peak periods to meet their demand and save water to meet peak period demand and reduce the use of coal-fired electricity. Decreasing transmission capacity under this scenario will increase emissions because the wind will not be able to be stored and BC Hydro must make greater use of thermal generation.

Although wind appears to be good for both lowering the costs of operating the system and decreasing greenhouse gas emissions, costs do eventually increase as the penetration of wind grows. In a drought scenario with lots of transmission capacity, it is relatively inexpensive to reduce emissions because the hydroelectric dams have capacity to store anything they can get and thermal generation would otherwise be running to meet energy requirements. However, in normal water years with lots of wind, the effect on greenhouse gas emissions is not as pronounced. This occurs because hydroelectric generation is naturally less expensive than thermal generation and, if there is energy available in excess of demand, it will be used to displace the thermal generation. In the model the thermal generators are constrained by a minimum output and, if the hydroelectric generators are already driving down the output of the thermal generators, wind that would otherwise displace dirty generation is discarded because the energy is not needed and there is no capacity for storage. This effect is more pronounced when wind is quadrupled and transmission is limited.

Chapter 5: The Marginal Value of Storage

In chapter 4 the value of new transmission for the integration of renewables was explored without direct consideration for the value of the storage provided by the hydroelectric dams themselves, which will be considered here. For the analyses in this chapter and the next, imports and exports from British Columbia to the United States are included. This has been done by taking the historical data for the year 2008 on which the wind and water flow data were also based. Equation (2) in Chapter 3 is adjusted by adding another term that represents net exports to the States,EX_{BC}^{US}:

$$(14) \qquad \sum_{i}^{N_p} Q_{i,t,p} - L_{t,P} - X_{t,P} - W_{t,P} - EX_{BC}^{US} = 0, for\ all\ P = AB, BC; t = 1, \dots, T$$

A more complete model would have the decision to export or import be endogenous to the model and dependent on the behavior of generation south of the border. This is not done here to reduce the complexity of the model.

Storage

Estimating the value of storage is a difficult problem, particularly in the case of a hydroelectric storage dam without pumped storage. A recent paper on valuing storage devices in the PJM Interconnection used arbitrage to value storage devices in general, without needing to make too many technical assumptions (Sioshani, Denholm, Jenkin, & Weiss, 2009). Unfortunately, a price based arbitrage approach is not possible in the framework selected for analysis here because I have assumed that the plant operators are price-takers in a perfectly competitive market and are minimizing costs. This approach fails to account for the price spikes that are common consequences of physical operating constraints in real electricity markets, but the results here could be thought of as the lower-bound of hydroelectric storage value in power systems.

Hydroelectric dams with storage ponds represent what is probably the simplest approach to storing energy in the power system. When there is plenty of electricity being generated by wind plants in the system, water can be prevented from entering the penstocks and the energy is stored behind the dam instead. Assessing the storage capacity of a dam requires consideration of two factors: (1) The volume of water that the head pond can hold, and (2) the rate of inflow of water into the head pond. To see this, it is worth considering the case of a flywheel. Each of these devices is faced with the same two constraints. A flywheel has physical limits on the velocity at which it can spin limiting the amount of energy that it can store. This is measured in kilowatt-hours and is analogous to the volume of water in the reservoir. The flywheel also has a limit on the acceleration of the flywheel. This is the rate at which energy can be stored and released from the flywheel and is thought of in terms of instantaneous power and measured in kilowatts. The same limit for a storage dam is the rate at which water flows into the head pond.

To assess the value of additional storage in the model discussed in Chapter 3, it is necessary to separate these two aspects of storage. All the runs of the model showed that the actual storage volume of the head pond is never constraining so an additional unit of storage behind the dam (measured in cubic metres) has zero value in the scenarios considered. This means that the value of additional storage can be considered by incrementally increasing the flows into head ponds and using the model to estimate the impact this has on the cost of running the power system.

Unfortunately, this approach raises another question of knowing whether or not a decrease in costs represents the incremental value of storing wind in the system or simply the marginal value of energy from more water being available. I take the stance that a decrease in costs from an incremental increase in inflows can always be interpreted as the value of more water in the system and sometimes it is also the value from storing wind energy. If the only thing that changes in the model is the amount of wind energy in the system then a decrease in costs from the incremental water flows can be attributed to the storage capacity enabled by more water flowing into the head ponds.

To arrive at the incremental value of storage all the scenarios from chapter 4 are revisited and the water inflows are incremented by 10%. In all of these scenarios the difference in costs and the change in electricity output measured in MWhs between incremented and base scenarios are considered. To get the marginal value of the water and storage the incremental cost savings are divided by the additional MWhs to give the added value of water in dollars per megawatt-hour.

Table 3. Value of Marginal Water Flows and Storage: Normal Flow Scenario ($/MWh)

Transmission Capacity	0x Wind	1x Wind	2x Wind	4x Wind
600 MW	54.10	54.69	56.10	59.95
1000 MW	53.24	39.79	39.03	37.90

The results from these calculations are shown in Tables 3 and 4. The first of these tables shows the results for the scenarios under normal flow conditions. The first value in the upper-left corner shows the marginal value of the additional water with no power in the system. This value is simply the marginal value of being able to produce more electricity from the additional water. Scenarios with increasing quantities of wind capacity are to the right. Seen this way, the marginal storage value can be seen as the difference in value from the base case with no wind and the other scenarios with increasing quantities of wind. This would suggest that the marginal value of storage between the zero wind scenario and the four times wind scenario is $5.85/MWh.

In the second row where transmission capacity has been increased, the value of the incremental water flows actually decreases suggesting that the marginal value of storage is decreasing. This occurs because, although more energy can to be stored behind the dam with increased transmission capacity, it is used at increasingly lower value times. In other words, the first MWhs of stored energy will be used to displace electricity from expensive gas peaker plants and successive output will be used to displace combined cycle gas plants and eventually even cheap coal will be replaced if there is sufficient storage capacity and wind energy to be stored.

Table 4. Value of Marginal Water Flows and Storage: Drought Flow Scenario ($/MWh)

Transmission Capacity	0x Wind	1x Wind	2x Wind	4x Wind
600 MW	**84.15**	**84.10**	**84.08**	**84.07**
1000 MW	**84.20**	**84.16**	**84.15**	**84.10**

Table 4 tells a different story. As would be expected, the marginal value of water is much higher under drought conditions because water is scarcer, but there is very little difference in marginal values between scenarios. Because of the scarcity of low cost energy in drought conditions, the dams are fully utilized and the wind energy is consumed as soon as it is captured resulting in zero storage value.

The results of these simulations suggest that the incremental value of having more storage for wind energy at these two levels of transmission capacity is near zero. It is likely that if this simulation could be modeled at a smaller time resolution (i.e. less than hourly time steps) and transmission and generation outages had been modeled within the power systems storage would be valued higher. This is because most of the problems associated with wind occur within hourly scheduling intervals and there are few problems adjusting generation to meet wind ramps when the power system is in a stable equilibrium. Far more trouble arises when transmission and generation is lost unexpectedly and resources must be ramped quickly to adjust. In these circumstances, storage accompanied by the ability to ramp output quickly (both characteristics of hydroelectric storage dams) is much more valuable than indicated by this model.

Chapter 6: Effect of Wind on the Use of Storage Dams

Jurisdictions throughout North America have been struggling with questions about the extent to which renewable energy should be used to provide power to consumers and the sufficiency of existing infrastructure to handle new technologies, such as plug-in hybrids and electric vehicles, that stand dramatically to increase the consumption of energy delivered by the electricity grid. The province of British Columbia is no exception. The Government of British Columbia recently released their Green Energy Act, which calls for the simultaneous development of the province's renewable energy export capabilities while mandating energy self-sufficiency and preparing for the transition to electric vehicles; it also calls for the decommissioning of the province's large natural gas generator, Burrard Thermal (2010 Legislative Session, 2010). The results of the model in this thesis suggest that these policy goals cannot be pursued simultaneously without massive investment in infrastructure.

Power and Energy

In policy discussions related to the management of the power system, the difference between power and energy is frequently confused. Energy is the ability to accomplish work. If you wanted to use a mechanical lift to put a heavy box on a shelf, you would require energy to accomplish this work and if this lift was powered by electricity you would use kilowatt-hours to measure the energy required to life the box. If you then decided that the box needed to be lifted in a shorter period of time, the lift would have to move faster and you would be changing the rate at which energy was used.

This is power and it is measured in kilowatts for the power system. From the time when people start getting up in the morning to the late-afternoon, people continuously demand more electricity and the rate at which we use energy increases. These power requirements must be met by generators that have the ability to change power outputs quickly. Some generators, like nuclear and coal powered facilities, are able to produce energy at low marginal cost but it takes a lot of time for these generators to change the rate at which they can capture energy and transform it into the currency of electricity. To make sure that we have the energy we need to boil water for pasta when we get home from work we need generators that can change their power outputs more quickly; single cycle gas generators and hydroelectric usually play this role in most modern power systems.

As pointed out by Sopinka and van Kooten (2010) ,these different aspects of energy delivery have value and BC Hydro's less common ability to ramp their power output rapidly is worth a great deal. It is worth something not only to British Columbia's grid but to neighbouring power systems as well, as these are willing to pay a premium during peak demand periods to make use of the ramping speed.

In a recent paper, (Kelly, Williams, Kerrigan, & Crawford, 2009) showed that BC Hydro's dams have the potential to provide enough power to meet an influx of electric vehicles. That is to say, when an electric car is plugged into the grid this rapid increase in the rate of energy consumption will require that a generator instantaneously increases its output to meet this change in demand, and BC Hydro has sufficient capacity to meet these changes for the foreseeable future. The paper carried on to say that providing the energy for these vehicles is a different problem and would require reducing exports to neighbouring Alberta. While this is surely true, the model here suggests that the situation is even more severe than that.

British Columbia: An Energy Constrained Electricity Grid

To understand the energy limitations of the British Columbia electricity grid, two approaches are taken. The first is simply to run the two power systems, Alberta and British Columbia, completely isolated from each other with no ties to the United States. Under this scenario, where all loads must be met with local generation, the model for BC solves only during a full water year and it is does this at great cost because the province's fossil fuel generation, particularly Burrard thermal, must be used extensively to meet the peak loads. When water flows are decreased to simulate low water years (or alternatively growth in the load base), the model simply has no solution. These simulations suggest that British Columbia is currently close to being not self-sufficient for energy and certainly not self-sufficient in zero-emissions energy as the system requires the use of the Burrard Thermal plant. This implies that, although BC Hydro may have the potential to produce sufficient power for millions of electric vehicles, it does not have the energy to meet an influx of new loads. To meet these needs, British Columbia will have to import energy from its neighbours.

To understand the effects of increased renewable energy in this system, the transmission link between the provinces is reintroduced. The transmission link takes the capacity values for export from British Columbia to Alberta of 760MW and 1200MW and four wind scenarios with increasing capacity are also considered. Tables 5 and 6 show the results of these simulations for both the normal water flow scenarios and drought scenarios, respectively. The difference in total outputs from the hydro generators in British Columbia are shown along with net exports and the generation from Alberta’s fossil fuel generators as the transmission capacities are upgraded. Both the day-light periods, denoted On-Peak and night-time periods, denoted Off-Peak are considered.

The first thing to note in Table 5 is that the total energy output from the hydro dams stays constant when the transmission intertie is upgraded. This is a result of the energy constraints in the BC Hydro system. If there was excess energy available in the system it would be exported during peak hours to displace fossil-fuel generators in Alberta. Then energy must be imported in the off-peak hours to offset that which is exported in the on-peak hours. It is also interesting to note that as the wind capacity becomes quite large it displaces hydroelectric generation as the lowest marginal cost supplier of electricity at the peaks and the hydroelectric generation moves to displace fossil-fuel generation at night.

In Table 6, the effects of an energy constrained BC Hydro are readily apparent. The coal and gas production in the drought scenarios is much higher and when the transmission link’s capacity is increased it allows for the more efficient Alberta gas and coal generators to displace those in British Columbia. The optimal allocation of resources when transmission capacity is increased in this very energy constrained scenario uses the hydro dams to meet the day-time energy requirements with high ramps and then at night greater use is made of the fossil fuel generation in both provinces.

These scenarios make it clear that energy self-sufficiency in the province of British Columbia is an unrealistic goal that would require a great deal of investment in new base generation capacity that goes far beyond the 900 MW facility at Site C proposed in the Green Energy Act. I believe these scenarios make it clear that energy self-sufficiency in the province of British Columbia is an unrealistic goal that would require a great deal of investment in new base generation capacity that goes far beyond the 900 MW facility at Site C proposed in the Green Energy Act.

Table 5. Normal Water Flow Scenario. This table shows the changes in generator outputs and net exports (in MWhs) from British Columbia when the transmission capacities are upgraded from 760 MW export capacity to 1200MW. Positive net exports indicate an export from British Columbia to Alberta.

Zero Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**0**	**0**	**-5,883**	**-183**
On-Peak	**128,385**	**26,135**	**-225,088.63**	**-1,954**
Off-Peak	**-128,385**	**-26,135**	**219,205**	**1,771**
1x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**0**	**0**	**-5,957**	**-108**
On-Peak	**26,135.72**	**26,135.72**	**-182,862.27**	**-842**
Off-Peak	**-26,135.72**	**-26,135.72**	**176,904.44**	**734**
2x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**0**	**0**	**-5,957**	**-108**
On-Peak	**-110,586**	**26,135**	**-94,523**	**-151**
Off-Peak	**110,586**	**-26,135**	**88,565**	**43.69**
4x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**-6**	**0**	**-5,449**	**0**
On-Peak	**-11,681**	**26,135**	**-184,778**	**0**
Off-Peak	**11,675**	**-26,135**	**179,329**	**-82**

Instead, this research suggests that we would be better off continuing to use our dams to meet the power requirements of BC Hydro and the Alberta and improving transmission infrastructure to leverage the value of this power and to import energy when it is needed to meet unsatisfied energy requirements at lowest cost. I believe that extending the model to include the Pacific Northwest would show similar results and an extension of the model in this regard would make the model more complete.

Table 6. Drought Water Flow Scenario. This table shows the changes in generator outputs and net exports (in MWhs) from British Columbia when the transmission capacities are upgraded from 760 MW export capacity to 1200MW.

Zero Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**-506**	**0**	**1,032,864**	**883,217**
On-Peak	**459,586**	**26,135**	**208,607**	**433,694**
Off-Peak	**-460,093**	**-26,135**	**824,257**	**449,522**
1x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**-458**	**0**	**1,586,750**	**980,179**
On-Peak	**336,635**	**26,135**	**472,619**	**634,021**
Off-Peak	**-337,094**	**-26,135**	**1,114,131**	**346,158**
2x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**-490**	**0**	**2,230,387**	**719,790**
On-Peak	**171,408.00**	**26,135.72**	**888,553.66**	**507,926**
Off-Peak	**-171,898.39**	**-26,135.72**	**1,341,833.80**	**211,863**
4x Wind Scenario				
	Hydro BC	**Net Exports**	**AB Coal**	**AB Gas**
Total	**-814**	**0**	**2,926,356**	**268,743**
On-Peak	**126,964**	**26,135**	**1,378,267**	**190,272**
Off-Peak	**-127,779**	**-26,135**	**1,548,089**	**78,471**

Chapter 7: Discussion

The infrastructure of the traditional electricity grid was developed in a world of vertically integrated utilities that were managed by the government to further economic development goals. Distribution, transmission and generation capacity were designed to meet an annual electric peak that lasted only a few minutes and the consumer was delivered electricity on demand at low, regulated prices. This system gave consumers no incentive to understand the trade-offs associated with their consumption behaviour. Generation had to be able to follow quickly changing consumption throughout the day to keep the load and generation balanced.

Deregulation of the power system is making it increasingly difficult for the consumer to be sheltered from the costs of their consumption decisions. Infrastructure built in a regulated environment is now reaching carrying capacity more often, frequently driving prices two orders of magnitude higher than normal. Incentive programs have been introduced to get some large electricity users to reduce their consumption during particularly price sensitive periods. Intermittent renewables are exacerbating the traditional problem of having generation follow variation on the demand side; generators must also make up for greater variation on the supply side. Electric vehicles unmanaged will only serve to exacerbate this problem.

To make better use of ageing infrastructure and integrate intermittent renewables and electric vehicles, a variety of technologies that emphasize the use of storage and control of loads are being suggested. To accelerate these changes the U.S. Federal Energy Regulatory Commission (FERC) delivered rulings No. 890 and No. 719 (2007, 2009) that mandate a level playing field for all types of market participants, including loads, renewable generators, and energy storage facilities in the energy and ancillary markets. As a result, deregulated electricity grids in the United States have been much quicker than their regulated counter parts to begin the process of transforming the power system to integrate the challenges posed by climate change, ageing infrastructure and increasingly volatile prices of fossil-fuels. Changes that many of the ISOs are pursuing include the development of time-of-use and real-time pricing schemes that are functions of market clearing prices, the development of protocols to integrate electric vehicles and manage their charging schedules, the inclusion of storage devices in energy and ancillary service markets, and the encouragement of new merchant transmission development. All of these changes should improve the capacity factor of existing transmission and distribution infrastructure and increase the reactiveness of the power system to changes on the supply-side caused by renewables. These infrastructure changes all encourage the use of prices as the appropriate medium for communicating information about the scarcity of resources in the power system.

Changes in the Pacific Northwest

In addition to the problems associated with ageing infrastructure and the integration of renewable energy and electric vehicles, the government of British Columbia has decided to add energy self-sufficiency to their list of problems to solve. The models discussed in this thesis show that, not only is the goal of energy self-sufficiency unlikely to be met with existing generation facilities, but that increasing transmission capacity and trade with a neighbouring transmission system is a cost-effective means of reducing greenhouse gas emissions in the region. This suggests that self-sufficiency is counterproductive for achieving progress in any of the other problem areas.

These results suggest that the approach of using open-access transmission tariffs and broader regional markets, as emphasized by FERC, could have important lessons for the power systems in British Columbia and the U.S. Pacific Northwest. These utilities are slow to adopt rules and operating procedures that would accelerate the development of cost-effective storage technologies and price-responsive loads and fail to provide the signals to the market place for the adoption of the technologies that are the most cost-effective means of mitigating climate change.

A regional Independent System Operator in the Pacific Northwest would be able to provide better price signals to market participants, develop consistent rules governing the integration of renewables and electric vehicles, coordinate transmission upgrades and development, and reduce utility operating costs. Focusing on the energy security of a single region while pursuing greater export capability may be counter-productive to the whole region; such insulated thinking could precipitate further events like the rolling blackouts in the Northeastern United States. More regional integration and coordination is needed, not less, especially as we accelerate the integration of variable and uncertain power sources into the grid.

Future Research

Future research programs should explore the feasibility and effectiveness of adopting a regional system operator responsible for the management of the transmission system and playing the role of the market maker for all market participants. Interesting questions related to climate change and renewable energy would include the following:

- What effect would establishing an ISO have on regional greenhouse gas emissions?
- How would renewable energy development in the region affect market prices and the consumer?
- How would real-time pricing affect the behaviour of consumers? Would this aid or confound the integration of intermittent renewables?
- What would coordinated transmission infrastructure upgrades look like? How would they effect greenhouse gas emissions and costs to consumers?
- How are the regional benefits and costs associated with infrastructure development allocated to market participants, especially in light of the particular transmission requirements of renewable energy developments?
- What are the patterns of adoption for electric vehicles in the region? How do they affect load patterns and market prices?
- What is the value of hydroelectric storage in the broader regional context? What about the value associated with the ability to change power output quickly?
- How will climate change affect the hydroelectric resources in the region and how will consumer behaviour change in response to changing weather patterns?

Future models exploring these questions should focus on capturing system behaviour at finer time-scales than the one hour time-steps that are now common in the literature. Much of the interesting (and costly) behaviour associated with intermittent renewables and electric vehicles happens on the order of minutes to hours, not hours to days.

When treating issues surrounding energy storage and the development of new transmission infrastructure, it is important to have good models of market prices and how they are affected by generator and intra-regional transmission constraints to provide good estimates of the value of these developments. Sophisticated modeling of the market clearing mechanism and consumer behaviour in the face of real-time pricing would also provide far more accurate estimates of the costs and benefits associated with the questions above.

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Appendix A: Data Table

Data Type	Source	Year
Wind Data	ets.aeso.com	2008
Alberta Generator Capacities**	ets.aeso.com	2008
Self-Scheduled Generator Capacities	ets.aeso.com	2008
Alberta Load Data	ets.aeso.com	2008
BC Generator Capacities	bchydro.com	2008
BC Load Data	bchydro.com	2008
Transmission Constraints	AESO OPP304 (aeso.com)	2008
BC Hydro Dams*	Potential output was calculated based on theoretical maximal output and the head height of the dams.	Average Past 50 years
Alberta Dams*	Potential output was calculated based on theoretical maximal output and the head height of the dams.	2008

*Dams included separately in the model were Williston Dam, Kinbasket Dam, Revelstoke Dam, and the Peace Canyon Dam and the reservoirs modeled that served these dams included GM Shrum Reservoir, the Mica Reservoir, the Revelstoke Reservoir and the Dinosaur Reservoir. The data obtained for these inflows was a 50 year average of the inflows available from the Water Survey of Canada (www.wsc.ec.gc.ca/hydat/H20). Similarly water data for the Brazeau and Bighorn dams in Alberta were also obtained from the Water Survey of Canada.

**Alberta generators, with the exception of the hydroelectric dams mentioned in the note above, were aggregated by unit type in the model, so that all coal, combined cycle gas, peaker, biomass, combined heat and power, wind, and run-of-river hydro were considered to be each a single unit with an efficiency equal to the average efficiency of the units in the aggregation.

Appendix B: Computer Code

GAMS Code

The following section contains the code used to run in GAMS:

```
$Title AB_BCStorage
option iterlim = 1000000;
*ALBERTA - BRITISH COLUMBIA POWER SYSTEM MODEL*
*THE PURPOSE IS TO EVALUATE THE COST OF INCREASING THE TRANSMISSION
*CAPACITY BETWEEN BC AND ALBERTA FOR THE PURPOSES OF BETTER INTEGRATION
OF
*WIND POWER IN ALBERTA

SETS
BC          BC Generators    /shrum, mica, revel, peace, hydro, burrard,
therm /
hBC(BC)     Hydro Reservoirs   /shrum, mica, revel, peace /
* GM Shrum, Mica, Revelstoke, Peace Canyon, remaining or other hydro,
* Burrard, remaining or other thermal (NG generators)
* GM Shrum, Mica, Revelstoke and Peace Canyon have reservoirs
;

*--Alberta Specific SET DATA-------------------------------------------
SETS
AB         AB generation /coal, NG, bighorn, brazeau, cogen, bow, bio,
wind, peak/
b(AB)      base load generation  /coal, NG/
hAB(AB)    hydro generation     /bighorn, brazeau/
m(AB)      Must-run generation  /cogen, bow, bio, wind/
;

*-----------Model SETS-------------------------------------------------
SET
t        The time dimension for this dynamic optimization   /1*8761/
         endts(t);
         endts(t)=yes;
         endts("1")=no;

SET
tinit(t)  first time period
;
tinit(t)=yes$(ord(t) eq 1);

SET
tfinal(t)  final time period
;
tfinal(t)=yes$(ord(t) eq card(t));


*Variables and scalars related to Matlab
***********************************************************************
* ----------- OUTPUT DATA FROM GAMS TO MATLAB -------------------------
```

```
SCALAR exitflag     status after solver has finished;
SCALAR fval
PARAMETER GnBC(t,BC)
PARAMETER GnAB(t,AB)
PARAMETER VBC(t,hBC)
PARAMETER Qtb(t,hBC)
PARAMETER Qspl(t,hBC)
PARAMETER VAB(t,hAB)
PARAMETER QtbAB(t,hAB)
PARAMETER QsplAB(t,hAB)
PARAMETER SkBC(t)
PARAMETER SkAB(t)
PARAMETER PowBCtAB(t)
PARAMETER PowABtBC(t)

* ------------ INPUT DATA FROM MATLAB GAMS CALL -----------------------

* ----------------- BC PARAMETERS -------------------------------------
* BC Load
PARAMETER  LoadBC(t)      load for each hour in BC;
*BC Hydro Generation
PARAMETER StartVolBC(hBC)   Starting volume for reservoirs;
PARAMETER QinBC(t,hBC)   Inflow into reservoirs from basin drainage;
PARAMETER QoutMinBC(t,hBC) Minimum outflow from reservoirs;
* Other BC parameters
PARAMETER  MaxGenBC(BC)     Maximum generation for each generator;
PARAMETER EffBC(hBC)    Efficiency of BC's hydro dams or turbines;
PARAMETER HeadBC(hBC)   Head height for each of BC's hydro generators;
PARAMETER VolMaxBC(hBC) Maximum reservoir operating volume;
* BC Cost parameters
PARAMETER FuelCostBC(BC)  Constant Fuel Cost;
PARAMETER VarOM_BC(BC)    Variable O&M Cost;
PARAMETER FixOM(BC)       Fixed O&M Cost;

* -------------- ALBERTA PARAMETERS ------------------------------------
------
* Alberta Load
PARAMETER  LoadAB(t)        load for each hour in Alberta;
*Alberta Hydro Generation
PARAMETER StartVolAB(hAB)  Starting volume of reservoir;
PARAMETER QinAB(t,hAB)     Inflows into Abraham Lake & Brazeau
reservoirs;
PARAMETER QoutMinAB(t,hAB) Minimum outflow from reservoirs through dam;
PARAMETER VolMaxAB(hAB)    Maximum reservoir operating volume;
PARAMETER EffAB(hAB)       Efficiency of Alberta's hydro turbines;
PARAMETER HeadAB(hAB)      Head height for each Alberta hydro
generator;
PARAMETER HydroMaxAB(hAB)    Max ouput of Alberta's dams in MW;
*Alberta Self-schedule
PARAMETER MustRunAB(t,m)   Must run cogen Bow River biomass and wind;
* Othere Alberta parameters
PARAMETER StartBase(b)  ;
PARAMETER MinGenAB(b)   ;
PARAMETER MaxGenAB(b)   ;
PARAMETER BaseRamp(b) MW per hour;
* Alberta cost parameters
```

```
PARAMETER FixCostAB(b)                       ;
PARAMETER VarOM_AB(b)    dollars per MWh;
PARAMETER FuelCostAB(b)   dollars per MWh ;
* Alberta Peaking
SCALAR MaxGenPeak ;
SCALAR FixCostPeak ;
SCALAR VarOMPeak  ;
SCALAR FuelPeak  ;

* ------------------ TRANSMISSION PARAMETERS FROM MATLAB --------------
SCALAR TransCapABEx  Transmission Capacity Alberta to BC;
SCALAR TransCapBCEx  Transmission Capacity BC to Alberta;
SCALAR SinkCap       Sink for measuring wasted renewables;
SCALAR TransCost     Annual amortized cost per MW of new transmission
line;

* --------------------- MATLAB READ -------------------------------
$if exist matdata.gms $include matdata.gms

* ---------- END OF MATLAB - GAMS EXCHANGE DATA DESCRIPTION -----------

* ------------ MODEL VARIABLES ----------------------------------------
POSITIVE VARIABLES
* British Columbia
GenBC(t,BC)      Generation from each generator in BC [MW]
VolBC(hBC,t)     Volume of Resevoirs [MM m^3]
Qturb(hBC,t)     Flow into turbine   [MM m^3 per hour]
Qspill(hBC,t)    Flow spilled by bypassing turbine [MM m^3 per hour]
SinkBC(t)        Storage OR Wasted Renewables
* Alberta
GenAB(t,AB)      Generation from each generator in AB [MW]
VolAB(t,hAB)     Volume of Resevoirs [MM m^3]
QturbAB(t,hAB)   Flow into turbine   [MM m^3 per hour]
QspillAB(t,hAB)  Flow spilled by bypassing turbine [MM m^3 per hour]
SinkAB(t)        Storage OR Wasted Renewables

;

VARIABLES
Z                Objective Value - Total System Cost [CAD]
PowBCtoAB(t)     Power flow from BC to AB [MW]
PowABtoBC(t)     Power flow from AB to BC [MW]
;

* ------------ MODEL EQUATIONS ----------------------------------------
EQUATIONS
minCost     The COMBINED objective function to be minimized

* ---- BC EQUATIONS -----------------------------------------------
demandConsBC(t)      Demand must be met in every hour for British
Columbia
hydroBCPower(t,hBC)  Equation for turbine flow for BC
ResVolShrum(t)               Reservoir Balance for Williston Res.
ResVolMica(t)               Reservoir Balance for Kinbasket Res.
ResVolRevel(t)               Reservoir Balance for Revelstoke Res.
ResVolPeace(t)               Reservoir Balance for Dinosaur Res.
```

```
StartVol(t,hBC)
MinOutFlow(t,hBC)    Lower Limit for Flow out of Resevoir
MaxResVol(t,hBC)     Maximum Resevoir Volume
CapConsBC(t,BC)      Capacity Constraint for BC generators

* ----- ALBERTA EQUATIONS -------------------------------------------
demandConsAB(t)    Demand must be met in every hour for Alberta
baseRampUp(t,b)    Ramp-Up Constraint for the Alberta Base generation
baseRampDown(t,b)  Ramp-Down Constraint for the Alberta Base generation
startGenAB(t,b)    Starting Generation Levels for Base Generation in
Alberta
minOutBase(t,b)    Minimum Output for Base Generation in Alberta
maxOutBase(t,b)    Maximum Output for the Base Generation in Alberta
MustRunEq(t,m)     Must run Output Constraint
peakCons(t,AB)     Peak Generation Constraint
* Alberta hydro dams
hydroABPower(t,hAB)  hydroAB Equation from turbine flow
ResVolAB(t,hAB)          Reservoir Balance for Big Horn and Brazeau
Reservoirs
StartVol_AB(t,hAB)
MinOutFlowAB(t,hAB)      Lower Limit for Flow out of Resevoir
MaxResVolAB(t,hAB)       Maximum Resevoir Volume
hydroOutputCons(t,hAB)   Ensures that Hydro Gens in AB do not exceed
maxOut

* ---- TRANSMISSION EQUATIONS -----------------------------------------
-
CabBal(t)                Cable power balance between BC and AB
CabLowerOne(t)           Lower limit for transmission from BC to AB
CabUpperOne(t)           Upper limit for transmission from BC to AB
CabLowerTwo(t)           Lower limit for transmission from AB to BC
CabUpperTwo(t)           Upper limit for transmission from AB to BC

* ----- SINK EQUATION -------------------------------------------------
-
SunkEnergyBC(t)        amount of stored or wasted renewables in sink
SunkEnergyAB(t)        amount of stored or wasted renewables in sink
;

*----OBJECTIVE FUNCTION------------------------
** ORDER OF OBJECTIVE FUNCTION COMPONENTS - Objective in $ millions,
* Water volume component negligible
* NEEDS ALBERTA GENERATION and IMPORT/EXPORT
* Line 1: BC Fuel and Var O&M Cost
* Line 2: BC Fixed O&M Cost
* Line 3: AB Base Generation fixed Cost
* Line 4: AB Variable O&M and Fuel Cost
* Line 5: Alberta Peak Generation Costs
* Line 6: must-run Generators (NEED COSTS!!!!!!)
minCost..
   Z =E= ((sum((t,BC),(FuelCostBC(BC)+VarOM_BC(BC))*GenBC(t,BC)))
         +(sum(BC,MaxGenBC(BC)*FixOM(BC)))
         +(sum(b,FixCostAB(b)))
         +(sum((t,b),(VarOM_AB(b)+FuelCostAB(b))*GenAB(t,b)))
         +(sum((t),(VarOMPeak+FuelPeak)*GenAB(t,'peak'))))*0.000001 ;
```

```
* -------- BC EQUATIONS ------------------------------------------
*Demand Constraint Equation, there should be import/export in this
equation
demandConsBC(t)$(not(tinit(t)))..
     sum(BC,GenBC(t,BC))-LoadBC(t)-PowBCtoAB(t)-SinkBC(t)=E=0;


* hydroBCPower = density*gravity*efficiency*Head*Flow
* hydroBCPower = ScalingFactor*Head*Flow*Efficiency
* Scaling factor includes gravity constant, water density,*W-MW
conversion,
* and [MMm^3/s] to [m^3/s] conversion
* The 3600 scaling factor included for the flow rate converts
* [flow/hour] to [flow/s] for the power equation

*hydroBCPower(t,hBC)$(not(tinit(t))).. GenBC(t,hBC) =E=
*           9807*HeadBC(hBC)*(Qturb(t,hBC)/3600)*EffBC(hBC);

hydroBCPower(t,hBC).. GenBC(t,hBC) =E=
9807*HeadBC(hBC)*(Qturb(hBC,t)/3600)*EffBC(hBC);

ResVolShrum(t)$(not(tinit(t)))..
                 VolBC("shrum",t) =E= VolBC("shrum",t-
1)+QinBC(t,"shrum")-Qturb("shrum",t)-Qspill("shrum",t);

ResVolMica(t)$(not(tinit(t)))..
                 VolBC("mica",t) =E= VolBC("mica",t-1)+QinBC(t,"mica")-
Qturb("mica",t)-Qspill("mica",t);
*Revelstoke reservoir (j = 3) is fed directly from Mica reservoir (j =
2), plus inflow from basin
ResVolRevel(t)$(not(tinit(t)))..
                 VolBC("revel",t) =E= VolBC("revel",t-
1)+QinBC(t,"revel")+Qturb("mica",t)+Qspill("mica",t)
                 -Qturb("revel",t)-Qspill("revel",t);
*Peace Canyon reservoir (j = 4) is fed directly from GM Shrum reservoir
(j = 1)
ResVolPeace(t)$(not(tinit(t)))..
                 VolBC("peace",t) =E= VolBC("peace",t-
1)+Qturb("shrum",t)+
                 Qspill("shrum",t)-Qturb("peace",t)-Qspill("peace",t);




StartVol(tinit,hBC)..  VolBC(hBC,tinit) =E= StartVolBC(hBC);

MinOutFlow(t,hBC)$(not(tinit(t))).. Qturb(hBC,t) + Qspill(hBC,t)
                                           =G= QoutMinBC(t,hBC);

MaxResVol(t,hBC)$(not(tinit(t)))..  VolBC(hBC,t) =L= VolMaxBC(hBC);
CapConsBC(t,BC)$(not(tinit(t)))..   GenBC(t,BC) =L= MaxGenBC(BC);


* ------------------------ ALBERTA EQUATIONS -------------------------
*Demand Constraint needs the other Generators
```

```
demandConsAB(t)$(not(tinit(t)))..  sum(AB,GenAB(t,AB))-
SinkAB(t)-LoadAB(t)
                                        -PowABtoBC(t) =E= 0;

baseRampUp(t,b)$(not(tinit(t))).. GenAB(t,b)-GenAB(t-1,b) =L=
BaseRamp(b);
baseRampDown(t,b)$(not(tinit(t))).. GenAB(t-1,b) - GenAB(t,b) =L=
BaseRamp(b);

startGenAB(tinit,b)..             GenAB(tinit,b) =E= StartBase(b);
minOutBase(t,b)$(not(tinit(t))).. GenAB(t,b) =G= MinGenAB(b);
maxOutBase(t,b)$(not(tinit(t))).. GenAB(t,b) =L= MaxGenAB(b);
MustRunEq(t,m)..                  GenAB(t,m) =E= MustRunAB(t,m);
peakCons(t,AB)..                  GenAB(t,'peak') =L= MaxGenPeak;
*---Alberta Hydro----
hydroABPower(t,hAB)..    GenAB(t,hAB) =E= 9807*HeadAB(hAB)
                                 *(QturbAB(t,hAB)/3600)*EffAB(hAB);

ResVolAB(t,hAB)$(not(tinit(t)))..  VolAB(t,hAB) =E=
                                   VolAB(t-1,hAB) +
                     QinAB(t,hAB) - QturbAB(t,hAB) - QspillAB(t,hAB);

StartVol_AB(tinit,hAB)..    VolAB(tinit,hAB) =E= StartVolAB(hAB);
MinOutFlowAB(t,hAB)$(not(tinit(t))).. QturbAB(t,hAB) +
                             QspillAB(t,hAB) =G= QoutMinAB(t,hAB);
MaxResVolAB(t,hAB)$(not(tinit(t)))..  VolAB(t,hAB) =L= VolMaxAB(hAB);

hydroOutputCons(t,hAB)$(not(tinit(t))).. GenAB(t,hAB) =L=
hydroMaxAB(hAB);

* ----- TRANSMISSION EQUATIONS ----------------------------------------
*CabBal(t)$(not(tinit(t)))..        PowBCtoAB(t) + PowABtoBC(t) =E= 0;
CabBal(t)..        PowBCtoAB(t) + PowABtoBC(t) =E= 0;
CabLowerOne(t)$(not(tinit(t)))..   PowBCtoAB(t) =G= -1*(TransCapABEx);
CabUpperOne(t)$(not(tinit(t)))..   PowBCtoAB(t) =L= TransCapBCEx;

CabLowerTwo(t)$(not(tinit(t)))..   PowABtoBC(t) =G= -1*(TransCapBCEx);
CabUpperTwo(t)$(not(tinit(t)))..   PowABtoBC(t) =L= (TransCapABEx);

* ----- SINK EQUATIONS ------------------------------------------------
SunkEnergyBC(t)$(not(tinit(t)))..  SinkBC(t) =L= SinkCap;
SunkEnergyAB(t)$(not(tinit(t)))..  SinkAB(t) =L= SinkCap;

* --- MODEL, OPTIONS AND SOLVE ----------------------------------------
MODEL AlbertaBCLink /all/;

OPTION LP=CPLEX;

SOLVE AlbertaBCLink using LP minimizing Z;

* Variables returned to Matlab
exitflag=AlbertaBCLink.modelstat;
fval=z.l;
GnBC(t,BC)=GenBC.l(t,BC);
GnAB(t,AB)= GenAB.l(t,AB) ;
VBC(t,hBC) =VolBC.l(hBC,t) ;
```

```
Qtb(t,hBC) = Qturb.l(hBC,t) ;
Qspl(t,hBC) = Qspill.l(hBC,t) ;
VAB(t,hAB)= VolAB.l(t,hAB) ;
QtbAB(t,hAB)= QturbAB.l(t,hAB) ;
QsplAB(t,hAB) = QspillAB.l(t,hAB) ;
SkAB(t) = SinkAB.l(t) ;
PowBCtAB(t)= PowBCtoAB.l(t);
PowABtBC(t)= PowABtoBC.l(t);

execute_unload 'output.gdx' exitflag, fval, GnBC=GenBC, GnAB=GenAB,
  VBC=VolBC, Qtb=Qturb, Qspl=Qspill, VAB=VolAB, QtbAB=QturbAB,
  QsplAB=QspillAB, SkBC=SinkBC, SkAB=SinkAB, PowBCtAB=PowBCtoAB,
  PowABtBC=PowABtoBC;

* -------------- END -------------------------------------------------
```

Matlab Code

This section contains the MATLAB code which was used to organize the data and make a call to the GAMS solver:

```
%function [] = AB_BCStorage(SinkCapacity,
StartingVolumePercent,InflowScale)
%-----------------------------------------------------------------------
%This function models the interaction between the Alberta and British
%Columbia power systems to evaluate the value of improving transmission
%links between the provinces for the purposes of integrating renewables
in
%Southern Alberta
%
% In BC, two main hydro river systems are modeled (Peace River &
Columbia
% River), with two generators located on each river. GM Shrum and Peace
% Canyon fall on the Peace River. Mica and Revelstoke fall on the
Columbia
% River. All four generators have storage reservoirs, but the size of
the
% reservoirs for Peace Canyon and Revelstoke are quite small compared
to
% the size of GM Shrum and Mica reservoirs.
%
%In Alberta the major sources of generation (coal, basegas, peakgas,
hydro,
% wind, cogen and biomass) are modeled seperately.
%
% Currently the model minimizes cost over one year, in an hourly
% resolution. Fuel cost and variable O&M cost (both CAD/MWh) are
modeled in
% the optimization. Fuel cost is considered constant (no part load
% efficiency variance), but emissions are calculated using part
%load efficiencies.
% INPUTS TO THE FUNCTION ARE:
% SinkCapacity [MW]: The capacity of the additional sink in the network.
% This may not be needed, but is included for when wind is considered
in
% Alberta.
%
% StartingVolumePercent [-]: The starting volume of the reservoirs.
This
% is set as a percentage of the maximum live storage volume, ie, 0.8
for
% 80% starting volume. Starting volume is needed for the state
equations.
%
% InflowScale [-]: The inflow vectors into each reservoir are based on
50
% year averages. If you wish to model a drought or flood scenario then
you
```

```
% can scale the inflows into the reservoir. If want to use the
50 year
% average, then set this input as 1. For drought modeling, set this
input
% below 1, for flood modeling, set this input above 1.
%
% Original code written June 12 2007 by J. Maddaloni. Updated code
written
% by Hugh Scorah, Linda Wong and Cornelis van Kooten in Fall 2009
%-----------------------------------------------------------------------

clear all;

tic
inputFile = 'ExcelData\ABtoBCLink1.xls';
filestring = 'D:\users\xiu\droughtModel2\out-noWind-1xFlow-
1200MW.xlsx'; %outfile

% Getting the sets
gams2('AlbertaBCLink', 'getsets', 'BC','hBC','AB','hAB','b','m','t');

%input variables
%InflowScale=0.375;
%StartVolPercent=0.6;
InflowScale=1;
StartVolPercent=1;
SinkCapacity = 10000;
%Set the GAMS output to not include name tags, just numeric values
gams_output = 'std';

%-- BC SPECIFIC DATA ---------------------------------------------------
%Read in the demand profile and massage for GAMS inputting [MW]
%GAMS: LoadBC(t)
LoadBC = xlsread(inputFile, 'Load', 'A3:A8763');

% Reservoir inflow from basin data and rework for input to GAMS
[m^3/hour]
% GM Shrum Reservoir - Williston Dam
% Mica Reservoir - Kinbasket Dam
% Revelstoke Reservoir - Revelstoke Dam (basin inflow only: you must
add to
% this the inflow from Mica reservoir or Kinbasket dam.
% Dinosaur Reservoir - Peace Canyon Dam (no basin inflow into reservoir
% as the only inflow comes from GM Shrum reservoir outflow. Column of
0s)
% Kinbasket dam (GMShrum reservoir) is inflow for Peace Canyon
(Dinosaur)
% [GMShrum Kinbasket Revelstoke Dinosaur]
% GAMS: QinBC(t,hBC)
Qin=xlsread(inputFile, 'Input', 'A4:D8764');
Adjustment = 0.0000001*InflowScale; % first term converts to MM
m^3/hour
Qin = Qin.*Adjustment;
QinBC.val = Adjustment.*Qin;
%QinBC.val = Adjustment.*Qin;
QinBC.indices = {tIndices hBCIndices};
```

```
%Read the minimum outflow from a dam [m^3/hour] converted to [MM
m^3/hour]
% [GMShrum Mica Revelstoke PeaceCanyon] Name of dams =
% [Williston Kinbasket Revelstoke Dinosaur] Name of reservoirs
% GAMS: QoutMinBC(t,hBC)
QoutMinBC.val = 0.0000001.*[zeros(8761,2) ...
    xlsread(inputFile,'Input', 'E4:F8764')];
QoutMinBC.indices = {tIndices hBCIndices};

% Set maximum reservoir volume [MM m^3]
% Volume refers to live storage, not full reservoir storage. This means
% that this volume can be fully reduced to zero.
% GAMS: VolMaxBC(hBC)
VolMaxBC = [39472 14800 173 24]';
% Starting volume for Reservoirs [MM m^3]
% Set as a fractional percentage of the maximum volume.
% Starting volume is with respect to live storage, not full reseroir
% storage
% GAMS: StartVolBC(hBC)
StartVolBC = StartVolPercent*VolMaxBC;

% Set Efficiency for each hydro generator (0.93) (Assume constant for
now)
% [GMShrum; Mica; Revelstoke; Peace Canyon]
% This assumption refers to a peak efficiency for a Francis Turbine
% GAMS: EffBC(hBC)
EffBC = [0.93 0.93 0.93 0.93]';

% Set Head Height for each hydro generator [m] (Assume constant for
now)
% [GMShrum; Mica; Revelstoke; Peace Canyon]
% Head heights for Mica, Revelstoke and Peace Canyon were calculated
from
% peak power conditions, Head height for GM Shrum was calculated using
the
% average ratio between head and dam height for the three other
stations
% GAMS: HeadBC(hBC)
HeadBC = [128.3 186.6 124 38.4]';

% BC Generator Capacities, [MW]
% Generators are limited by Power Capacity, not water flow rate
%[GMShrum Mica Revelstoke PeaceCanyon RemainHydo Burrard OtherThermal]
% Remaining Hydro includes all BC hydro IPP
% Other Thermal includes all BC thermal IPP (Assume conventional NG
turbine
% GAMS: MaxGenBC(BC)
MaxGenBC = [2730 1805 1980 694 3135 913 563]';

% fuelCostBC - Constant fuel cost [CAD/MWh],
% varOM_BC - Variable O&M [CAD/MWh],
% FixOM - Fixed O&M [CAD/MW per year]
%-----------------------------------------------------------------------
% Hydro constant fuel cost = 1.101 CAD/MWh -
% 93% Francis turbine efficiency, water cost of 6.0e-6 CAD/m^3
```

```
% power cost of 1.086 CAD/MWh
% Conventional gas turbine fuel cost = 85.04 CAD/MWh -
% 36.5% thermal efficiency, NG cost of 31.04 CAD/MWh
%
% Hydro Variable O&M = 3.64 CAD/MWh - EIA/DOE
% Conventional gas turbine O&M = 3.70 CAD/MWh - EIA/DOE
% Fixed O&M  - EIA/DOE
%-----------------------------------------------------------------------
%Need fixed cost for burrard
%[GMShrum Mica Revelstoke PeaceCanyon RemainHydo Burrard OtherThermal]
FuelCostBC = [1.101 1.101 1.101 1.101 1.101 85.04 85.04]';
VarOM_BC = [3.64 3.64 3.64 3.64 3.64 3.70 3.70]';
FixOM = [14470 14470 14470 14470 14470 12930 12930]';

%-- END OF BC SPECIFC DATA ---------------------------------------------

%-- ALBERTA SPECIFC DATA -----------------------------------------------
LoadAB = xlsread(inputFile, 'Load', 'B3:B8763');
%--------- Alberta Base Load Generation -------------------------
% The first value is for COAL and the second for COMBINED CYCLE GAS
StartBase = [5000 158]'; % [Coal NG] Initial values
% minimum base generation
MinGenAB = [2587 82]'; % [Coal NG]
% maximum base generation
MaxGenAB = [5984 457]'; % [Coal NG]
% ramp speeds for the base generation in MW/hr
BaseRamp = [5984*.1 457*.2]'; % [Coal NG]
% fixed cost for base, zero for the moment
FixCostAB = [0 0]'; % [Coal NG]
% variable O&M for base generation  $/MWh
VarOM_AB = [0.61 0.25]'; % [Coal NG]
% fuel cost for base generation $/MWh
FuelCostAB = [19.80 44.82]'; % [Coal NG]

% ALBERTA PEAK GENERATION
MaxGenPeak = 272;
FixCostPeak = 12930;
VarOMPeak =0.25;
FuelPeak = 83.00;

%---- Alberta Hydro Generation, BigHorn & Brazeau dams, adjusted ----
% GAMS: QinAB(t,hAB)
QinAB.val=Adjustment.*xlsread(inputFile, 'Input', 'H4:I8764');
QinAB.indices={tIndices hABIndices};

% Minimum output value for the moment is 25 for Big Horn and Brazeau
% GAMS: QoutMinAB(t,hAB)
QoutMinAB.val = 0.0000001.*(zeros(8761,2)); % Convert flow to [MM
m^3/hour]
QoutMinAB.indices = {tIndices hABIndices};

% Set maximum reservoir volume [MM m^3] [Big Horn (Abraham L), Brazeau]
% Volume refers to live storage, not full reservoir storage. This means
% that this volume can be fully reduced to zero.
VolMaxAB = [0.480 1.424]';
StartVolAB = StartVolPercent*VolMaxAB;
```

```
%----------- Alberta Must-Run Generation -------------------
% [cogeneration BowRiver Biomass]
WindMultiplier = 0;
MustRunOut = xlsread(inputFile, 'Input', 'K4:M8764');
WindOut = WindMultiplier*xlsread(inputFile, 'Input', 'N4:N8764');
% GAMS: MustRunAB(t,m)
MustRunAB.val = [MustRunOut WindOut];
MustRunAB.indices = {tIndices mIndices};

% Set the Efficiency for each hydro generator (0.93) Constant for now
% This assumption refers to a peak efficiency for a Francis Turbine
EffAB = [0.93 0.93]';

% Set Head Height for each hydro generator [m] (Assume constant for
now)
% [Big Horn, Brazeau]
% NEED TO CALCULATE HEAD HEIGHT FROM PEAK POWER CONDITIONS
% Brazeau max output 355 MW
HeadAB = [128.3 186.6]';
HydroMaxAB = [120 355]';

%-- END OF ALBERTA SPECIFIC DATA ------------------------------------
----

%--- TRANSMISSION LINE DATA -----------------------------------------
----
% Existing transmission capacity between BC and Alberta [MW]
%See AESO OPP304 for details on Transmission constraints
TransCapABEx = 1000;  % (Normal is 600MW) WECC rated capacity is 1000
TransCapBCEx = 1200;  % (Normal is 760MW) WECC rated capacity is 1200
SinkCap = 5000;       % Sink for measuring WASTED RENEWABLES

% Cost for upgrading transmission capacity, $ per added MW of
transmission
% Amortized over 20 years at a discount rate of 10%. Initial cost =
% 61,700 CAD/MW amortized over 20 years
rate=0.1;
InitCost=61700;
factor=((1+rate)^20)/(((1+rate)^20)-1);
TransCost = rate*InitCost*factor;
%--- END OF TRANSMISSION LINE DATA ----------------------------------

% ---- PREPARING DATA FOR SUBMISSION TO GAMS: ADDING INDICES ----------
% Tagging vectors and matrices with corresponding indices from GAMS
% Vectors BC
LoadBC=[tIndices LoadBC]; StartVolBC=[hBCIndices StartVolBC];
MaxGenBC=[BCIndices MaxGenBC]; EffBC=[hBCIndices EffBC];
HeadBC=[hBCIndices HeadBC]; VolMaxBC=[hBCIndices VolMaxBC];
FuelCostBC=[BCIndices FuelCostBC]; VarOM_BC=[BCIndices VarOM_BC];
FixOM=[BCIndices FixOM];
%Vectors AB
LoadAB=[tIndices LoadAB]; StartVolAB=[hABIndices StartVolAB];
EffAB=[hABIndices EffAB]; VolMaxAB=[hABIndices VolMaxAB];
HeadAB=[hABIndices HeadAB]; HydroMaxAB=[hABIndices HydroMaxAB];
StartBase=[bIndices StartBase]; MinGenAB=[bIndices MinGenAB];
```

```
BaseRamp=[bIndices BaseRamp]; MaxGenAB=[bIndices MaxGenAB];
FuelCostAB=[bIndices FuelCostAB]; VarOM_AB=[bIndices VarOM_AB];
FixCostAB=[bIndices FixCostAB];


[QinBC QoutMinBC QinAB QoutMinAB MustRunAB] = fstruct2(QinBC, ...
    QoutMinBC, QinAB, QoutMinAB, MustRunAB);

% ------ END MATCHING DATA AND LABELS (SETS) TAKEN FROM GAMS ----------

% ----- GAMS CALL -----------------------------------------------------
% Make the GAMS call for the dynamic solution
alert1= 'Entering GAMS'
%gams2('AlbertaBCLink','LoadBC','StartVolBC','QinBC', 'QoutMinBC', ...
%  'MaxGenBC','EffBC','HeadBC','VolMaxBC','FuelCostBC','VarOM_BC', ...
%  'FixOM','LoadAB','StartVolAB','QinAB','QoutMinAB', ...
%
'VolMaxAB','FuelCostAB','EffAB','HeadAB','HydroMaxAB','MustRunAB', ...
%  'StartBase','MinGenAB','MaxGenAB','BaseRamp', ...
%  'FixCostAB','VarOM_AB','MaxGenPeak','FixCostPeak','VarOMPeak', ...
%
'FuelPeak','TransCapABEx','TransCapBCEx','SinkCap','TransCost','UEL');
%----------------------------------------------------------------------
gams2('AlbertaBCLink','LoadBC','StartVolBC','QinBC', 'QoutMinBC', ...
  'MaxGenBC','EffBC','HeadBC','VolMaxBC','FuelCostBC','VarOM_BC', ...
  'FixOM','LoadAB','StartVolAB','QinAB','QoutMinAB', ...
  'VolMaxAB','FuelCostAB','EffAB','HeadAB','HydroMaxAB','MustRunAB',  ...
  'StartBase','MinGenAB','MaxGenAB','BaseRamp', ...
  'FixCostAB','VarOM_AB','MaxGenPeak','FixCostPeak','VarOMPeak', ...
  'FuelPeak','SinkCap','TransCost','UEL');

exitflag = readgdx('output.gdx', 'exitflag');
exitflag

%Check GAMS optimality status
    if exitflag ~= 1  %1 if linear program; 2 if nonlinear program
        display('Local optimum not found in Energy Model');
        %return
    end

% fval = readgdx('output.gdx', 'fval');
% temp = readgdx('output.gdx', 'GenBC');
% temp(:,1)=temp(:,1)-max(temp(:,2)); %modify indices before calling
sp2full
% GenBC = sp2full(temp, 'param', [length(BCIndices) length(tIndices)]);
% clear temp;
%
% temp = readgdx('output.gdx', 'GenAB');
% temp(:,1)=temp(:,1)-max(temp(:,2)); %modify indices before calling
% sp2full
% GenAB = sp2full(temp, 'param', [length(ABIndices) length(tIndices)]);
% clear temp;
%
% sum(GenBC)

% Option 1
```

```
sp2f='no'; %prevent gams2 from automatically calling sp2full()
[fval,GenBC.val,GenAB.val,SinkBC.val,SinkAB.val,PowBCtoAB.val,PowABtoBC
.val, TransCap.val] =...

gams2('output.gdx','fval','GenBC','GenAB','SinkBC','SinkAB','PowBCtoAB'
,'PowABtoBC','TransCap');
GenBC.indices={tIndices BCIndices};
GenAB.indices={tIndices ABIndices};
SinkBC.indices={tIndices};
SinkAB.indices={tIndices};
PowBCtoAB.indices={tIndices};
PowABtoBC.indices={tIndices};
TransCap.indices={tIndices};


[GenBC GenAB  SinkAB PowBCtoAB PowABtoBC
TransCap]=sstruct2(GenBC,GenAB,SinkAB,PowBCtoAB,PowABtoBC, TransCap);
TransCap #print optimal transmission capacity

outAB = [GenAB SinkAB PowABtoBC LoadAB(:,2)];
outBC = [GenBC PowBCtoAB LoadBC(:,2)];


titleAB = ...
    {'Coal','NG','Bighorn','Brazeau','Cogen','Bow River',...
    'Biomass','Wind','Peak','SinkAB','PowABtoBC','Demand','Obj
Val=',fval};
titleBC = ...
    {'Shrum','Mica','Revelstoke','Peace River','Other Hydro',...
    'Burrard','Other Thermal','PowBCtoAB','Demand'};



xlswrite(filestring,titleAB,'Alberta','A1')
xlswrite(filestring,outAB,'Alberta','A2')
xlswrite(filestring, titleBC,'BC','A1')
xlswrite(filestring,outBC,'BC','A2')
toc
```