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Economic Evaluation of Wind Power in Alberta

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EXECUTIVE SUMMARY

To meet forecasted load growth in the Alberta electricity market, various power generation technologies are available. Each has different attributes, benefits and limitations. Wind power generation technology is an attractive option for the reduction of emissions however it also imposes additional costs relative to other technology options. The location, variability and intermittency of wind power generation in the Alberta system create reliability issues (supply always equaling demand in real-time) and efficiency issues that would not exist if no wind capacity was installed. Reliability can be more efficiently attained with less total installed generation and transmission capacity when wind is not in the system. The volatility of output from wind generation also imposes or transfers costs on load and other generators to manage reliability. In order to assess the trade-off between the benefits and costs of wind power generation in Alberta, the effects of wind on the electricity system and the costs it imposes should be analyzed. The effects of various public policies on the results of that analysis will also guide decisions to improve economic efficiency. Comparison of these costs to the benefits of wind as a renewable technology can assist in determining the required willingness to pay for wind as a renewable energy source. Alberta currently has the capacity to generate 939 MW of electricity from wind power, representing approximately 7% of installed capacity. This capacity has come at a cost and reduced market efficiency, as well as affected the objectives of all market participants. It is therefore questionable whether it is efficient to add more wind power capacity to the Alberta electricity grid.

The objectives of this paper are to:

- Provide a background of the Alberta electricity market including how it is currently operated
- Demonstrate the effects of the intermittency and volatility of wind in the electricity system and assess the correlation of wind resources in Alberta
- Assess the additional costs imposed by wind capacity and generation in the Alberta electricity market
- Assess the profitability of wind generators in the Alberta market
- Discuss the effects that current or potential public policies intended to promote wind generation have on these additional costs and on generator profitability
- Assess the cost of carbon abatement in Alberta
- Determine which, if any market, technology or policy solutions can improve the economic efficiency of wind generation in Alberta

The Alberta Interconnected Electric System is to be managed in a fair, efficient and openly competitive manner, and system reliability must be maintained. The location, variability and intermittency of wind power generation in the Alberta system create reliability and efficiency issues that would not exist if no wind capacity was installed and these issues increase system costs. Solutions to ensure reliability and balance supply and demand due to wind volatility require careful attention to the objectives of the system operator. System costs related to each of generation, transmission and operating reserves are greater when wind capacity is installed relative to a no wind scenario. These costs represent the economic value to society that is lost from using these resources to include wind generation in the system. These costs can be aggregated to determine the required willingness to pay for the benefits of wind as a renewable source of energy.

Load at winter peak is expected to grow from 10609 MW at the end of 2011 to 17281 MW by 2032. The forecast developed by the Alberta Electric System Operator was developed recognizing the challenges and uncertainty faced by the Alberta electricity market. Wind is generally available when demand (and price) is lower in spring and fall and not available during extreme temperatures when prices are higher due to higher demand. Coal fired generation currently provides the majority of the energy required by Alberta's market but it is unlikely that much new investment in coal will occur due to its high capital costs and increasing variable costs from recent or pending environmental regulations. Gas fired generation is projected to be the largest and fastest growing source of generation to meet growing demand, with a sizeable increase in combined-cycle gas turbines (CCGT) specifically. There are currently 15 wind farms in Alberta connected to the AIES. Current wind resources are primarily located in the south west of the province and the majority of wind farms are currently highly correlated, affecting the volatility of aggregate wind output. As of June 2012, twenty-eight new wind plants were in the queue for development. The choice of generation technology to meet load growth may be affected by political and regulatory uncertainty. The public policies implemented by federal, provincial and even international governments can have a direct or indirect effect on the relative costs of different generation technologies.

Additional costs imposed by wind are assessed by comparing wind capacity and generation currently in the system, and forecasted for development, to a scenario with no wind generation. The costs of additional generation and transmission capacity, less fuel savings are demonstrated to be in the range of $1.38 billion to $1.57 billion (2011$) as of today, relative to gas-fired generation, depending on which type replaces wind energy. The present value of these costs for the next ten years (2012-2022), if development occurs as planned today, would rise to $4.56 billion to $5.01 billion (2011$). Additional costs imposed for managing near-term reliability and to follow the volatility of wind are not included in these estimates however are greater for the scenario where wind is installed.

Wind generation, without including its green attributes, has been assessed to be unprofitable when costs are compared to revenue. Wind generators are currently unable to capture revenue seen by other generators, largely due to their must-run characteristic offering in the market at $0/MWh and their inability to take advantage of higher electricity prices. Wind generation in the system can also alter reserve margins, energy prices and expected returns on investment, affecting the profitability of other generators and therefore the signals to enter or leave the market. The low cost of CCGT and profitability of both CCGT and simple cycle gas turbines (SCGT) under current assumptions will incent investment in these technologies. The flexibility of SCGT and the relative efficiency of CCGT can also increase their individual attractiveness in meeting the needs of the long term forecast. Wind is neither flexible nor able to capture high pool prices in general due to the timing, availability and offer price of wind.

The current Alberta electricity market rules have created an advantage for wind generators at the expense of other market participants for a product that ultimately provides it lower value. If market rules continue to provide an advantage to wind generators such that they are neither required to submit offers nor be held accountable for their production, wind may remain relatively attractive to those who can earn revenue through specific financial arrangements or outside the market. Wind generators who do not face the true costs of their variable and intermittent generation are effectively subsidized by other generators or load. If not paying their full costs, there will be less incentive for cost reduction, and adequate solutions to improve the effects of the variability and intermittency of wind generation will not be sought to the level required to maximize economic efficiency. In addition, if wind developers do not have to pay their own costs, more wind development may occur which will increase the magnitude of the impact on social costs. If changes to the market rules do occur, and costs are allocated to wind generators, development in wind generation may not appear as attractive and would need to be reassessed based on new costs, such as the costs of storage, joint ventures with firm supply, or wind firming services.

Most of the current and politically favourable public policies that affect wind generation development focus on incentives to promote renewable energy directly, such as Renewable Energy Credits (REC's) and subsidies, and not reduce carbon emissions directly (pricing externalities). Subsidies and REC's have a much larger effect on levelized cost of energy (LCOE) than the current carbon price in Alberta in improving the relative attractiveness of wind generation to a generation facility owner. They also have the advantage of being less visible costs to consumers than other policies such as taxes. Policies should be careful not impose new social costs when they are intended to increase social benefits. The costs of carbon emissions and pollution should be allocated to emitters and not offset by encouraging the use of resources for alternate technologies that cannot reliably provide electricity in Alberta and which ultimately create new costs. The additional inefficiency related to these costs can be reduced or eliminated with the correct public policies. The present value of the cost of carbon abatement imposed by wind power generation in Alberta to date has been assessed to be $162.54/tonne and $257.62/tonne for SCGT and CCGT, respectively.

The additional costs imposed by wind generation in Alberta can be summarized into two parts. One, wind generation is being provided an advantage directly through subsidies or other policies that are not ultimately addressing, or sufficiently addressing the cause of the failure they are intended to address, i.e. inadequately priced carbon emissions. Two, wind generation is not a reliable source of energy and its intermittency, volatility and resource location require that additional costs be incurred for a benefit that is difficult to quantify. Wind is being subsidized indirectly through the socialization or transfer of its production costs, sending incorrect market signals and imposing costs that are ultimately an inefficient use of resources in the generation of electricity. These two costs are the result of two different inefficiencies, undervalue two sets of resources, and should be resolved by different solutions if wind power is deemed to be a desirable technology in the attainment of lowered carbon emissions and pollution.

Market rule changes, energy storage and carbon taxes would make wind power generation an efficient investment in Alberta however these will be difficult to achieve technologically and politically. Each does however solve a separate problem currently imposed by wind generators and each can individually improve economic efficiency in the Alberta electricity system and market, although none alone will eliminate all of the additional social costs or inefficiency. Additional improvements or gains in wind turbine technology may also improve development and reliability issues by allowing wind generators to develop in low wind areas with different wind profiles, however Alberta is a relatively small market and options may remain limited even with new technology. From an investor perspective, wind generation can be sufficiently subsidized with the right combination of revenue streams, however as additional wind is integrated into the AIES, and without changes to market rules, policy or improvements in technology, additional wind in the system will increase social costs of energy production. Renewable energy is a benefit to society however its current variability and intermittency make it difficult and costly to integrate. The social costs imposed from all electricity generation should be appropriately valued and paid. The cost of energy consumption is ultimately too low and equating private and social costs of all energy technologies will require prices to increase. This will result in the most efficient allocation of resources and properly value energy in society.

Qualifications:

- This analysis has been conducted specifically in relation to the Alberta electricity market.
- The benefits of wind are not discussed in any detail. This paper does not argue for or against wind, only indicates that it currently creates inefficiency in the market and the benefits it provides to society must be valued at at least the approximate minimum additional costs of wind power identified.

1.0 INTRODUCTION

In Alberta, the generation of electricity occurs in a deregulated, energy-only market. Additional generation capacity is required to meet growing demand in conjunction with the retirement of generation units, and wind is an option for developers. Alberta currently has the capacity to generate 939 MW of electricity from wind power, representing approximately 7% of installed capacity. This wind capacity was installed with the help of various federal subsidies, the latest of which was removed in early 2011. The incentive for a firm to invest in wind generation capacity is governed by the relative attractiveness of wind power versus other technology options. This is determined by a mixture of economic and technical parameters by which the levelized cost of electricity can be calculated. The costs of wind power to society include the socialized elements of the power system which must be altered to accommodate the addition of incremental wind power. These elements include transmission and reliability management costs, and the effects of wind on the optimal generation mix. Comparison of these costs to the benefits of wind as a renewable technology can assist in determining whether the benefits are worth the additional cost of wind relative to more economically efficient technologies. It is therefore questionable whether it is efficient to add more wind power capacity to the Alberta electricity grid.

Forecasted load growth in Alberta and a desire to reduce carbon emissions and other pollution will require assessment of which generation technologies may be most desirable for investment. Uncertainty about pending or potential regulations on carbon and other emissions from conventional power generation, and the emissions-free option of wind power may provide incentives to invest in wind power. Portfolio diversity in large power generation companies or social responsibility commitments may also make wind more attractive. Wind power generation is currently not however the least cost option for generation facility owners (GFO's) under comparable financing arrangements, nor does it provide significant revenue relative to other generation options from generation alone. The benefits of renewable power generation also currently come with additional social costs. These costs, in aggregate can reveal the required willingness to pay for wind energy and its benefits as a renewable energy technology however they also demonstrate economic inefficiencies that should be addressed if wind power generation in Alberta is desirable.

There are many benefits of wind power generation relative to other generation technologies. Wind power produces no air emissions from generation, offsetting the contribution from power generation to smog, acid rain and climate change. It also requires no water, and results in no hazardous or toxic waste, (CanWEA, 2012). Wind as a source of fuel is also completely renewable. The value of these benefits will vary between people, locations and groups and their willingness to disregard the effects of pollution, the use of natural resources, and climate change. If moving society away from fossil fuels is necessary to reduce the harmful effects of climate change, it will require investment in renewable generation technologies.

The power from wind however is not free. Wind power currently imposes costs that other technologies do not due to the intermittency and lack of control over wind as a fuel supply. It creates volatility in the power supply which is more difficult and costly to manage than firm, dispatchable power provided by other generators. Wind power also requires relatively more transmission infrastructure due to the location of the wind resources that provide the most attractive generation sites. It does not provide reliable capacity, providing variable power and relying on other generators to adjust their output to accommodate wind. It provides less value to the system operator than other technologies because it is much more limited in when it can be produced and because it cannot provide additional services to fulfill market needs outside the energy market. Gas-fired generation, for example, is very flexible and can be considered to offer higher value for power produced. Wind is typically available more during on-peak hours, however it is less valuable for more seasonal load requirements or extreme temperatures. Wind does have more certainty in long run costs as it is not dependent on fluctuations in fuel prices however wind generators cannot choose when to operate, cannot provide higher valued flexible generation, and have greater revenue risk as a price taker.

Additional costs imposed by wind are demonstrated by comparing wind capacity and generation currently in the system, and forecasted for development, to a scenario with no wind generation. The costs of additional generation and transmission capacity, less fuel savings are demonstrated to be in the range of \$1.38 billion to \$1.57 billion (2011\$) as of today relative to gas-fired generation, depending on which type replaces wind energy. The present value of these costs for the next ten years (2012-2022), if development occurs as planned today, would rise to \$4.56 billion to \$5.01 billion (2011\$). Additional costs imposed for managing near-term reliability and to follow the volatility of wind are not included in these estimates however are greater for the scenario where wind is installed.

The benefits from wind generation also depend on what type of generation it displaces. This is also dependent on the time it is produced. In Alberta wind generation is typically higher during the day displacing more gas-fired generation which has a lower emissions intensity than other types of generation such as coal. Wind generation requires greater material per MW of capacity and much larger land space than conventional generation (however it leaves less to reclaim once the wind plant reaches its end of life). The promotion of wind generation and other renewable power can also create inefficiency and impose costs on society when the inputs to produce electricity are undervalued. When inputs into the production of electricity do not correctly reflect social costs, consumers do not pay their full costs and it is over-consumed. This incorrect reflection of social costs can be a result of an underlying market failure and can be exacerbated by government intervention which indirectly or inadequately targets the underlying failure.

Most of the current and politically favourable public policies that affect wind generation development focus on incentives to promote renewable energy directly, such as Renewable Energy Credits (REC's) and subsidies, and not reduce carbon emissions directly (pricing externalities). Subsidies and REC's have a much larger effect on levelized cost of energy (LCOE) than the current carbon price in Alberta in improving the relative attractiveness of wind generation to a GFO. They also have the advantage of being less visible costs to consumers than other policies such as taxes. Policies should be careful not impose new social costs when they are intended to increase social benefits. The costs of carbon emissions and pollution should be allocated to emitters and not offset by encouraging the use of resources for alternate technologies that cannot reliably provide electricity in Alberta and which ultimately create new costs. The additional inefficiency related to these costs can be reduced or eliminated with the correct public policies. The present value of the cost of carbon abatement imposed by wind power generation in Alberta to date has been assessed to be \$162.54/tonne and \$257.62/tonne for SCGT and CCGT, respectively.

In order to assess the trade-off between the benefits and costs of wind power generation in Alberta, the effects of wind on the electricity system and the costs it imposes should be analyzed. This paper attempts that analysis. The effects of various public policies on the results of that analysis will also guide decisions to improve economic efficiency[1]. It is known that additional generation capacity is required to meet growing demand in conjunction with retiring generation units and that wind is an option for developers. It is also known that wind will require at least some back-up generation as it is not available at all times, will require additional bulk transmission due to its more remote fuel locations, and will require additional reliability management due to its volatility. If the cost of wind generation to a private investor falls, more generation from wind capacity may be installed. If renewable energy is promoted by public policy, and as a result is more attractive as an investment option relative to other technologies, more generation from wind capacity may also be installed. Both of these results would require that a greater amount of additional wind generation be accommodated by the system. These may be favourable outcomes for the reduction of emissions from energy production, however whether they will be economically efficient from a societal perspective is unclear.

This paper begins with a description of the Alberta electricity market including the current generation mix, long term forecast and public policy and regulatory outlook. Section 3 describes wind energy in Alberta and its effects, and assesses the correlation of current and planned wind capacity. Section 4 consists of an analysis of the costs of wind relative to a no-wind scenario on each of generation, transmission and operating reserves. Section 5 consists of an analysis of the private costs and revenues for wind generators and what would make investment in wind generation more attractive to a GFO. Section 6 discusses the effects of social and private incentives and objectives on one another, and the effects of various public policies on the incentives of market participants. Section 7 concludes. All appendices can be found in Section 8.

Alberta load, pool price, generation and other market data were taken from AESO publications, AESO data files, and databases subscribed to by ATCO Power. Wind speed and ambient temperature data was purchased from the National Climate Data and Information Archives of Canada and was used in conjunction with approximations for current plant geographic coordinates (longitude and latitude) to determine which weather stations were closest to which wind generation facilities. All calculations and data analysis were conducted in Excel. With the exception of Figures 3, 4, and elements of 5, all tables and figures were developed in Excel. All dollars are in $2011. Any inflation adjustments were calculated using the Bank of Canada's inflation calculator available on their website (Bank of Canada, 2012). The benefits of wind are not analyzed nor discussed in detail. This paper does not argue for or against wind, it suggest only that the benefits it provides to society must be equal to at least the approximate minimum additional costs of wind identified.

2.0 BACKGROUND

2.1 The Alberta Wholesale Electricity Market

The generation, transmission, distribution and retail sale of electricity in Alberta are connected through the Alberta Interconnected Electric System (AIES). The Electric Utilities Act requires that the system be operated in a fair, efficient and openly competitive manner. Coordination of the generation and transmission of electricity in the AIES is managed by the Alberta Electric System Operator (AESO), an

[1] Unless otherwise apparent, efficiency refers throughout this paper to economic efficiency and not production efficiency.

Independent System Operator who has a legislated mandate to ensure reliability of the system. Its activities, as well as the activities of all other market participants, are overseen by the Market Surveillance Administrator (MSA).

In Alberta, the generation of electricity occurs in a deregulated, energy-only market. The market was deregulated over the period of 1996 to 2001. Prior to deregulation, generators were regulated by the Alberta Energy and Utilities Board, (now Alberta Utilities Commission (AUC)). In the process of deregulation, the financial rights to the energy produced by formerly regulated assets were auctioned off through Power Purchase Arrangements (PPA's). Original owners received guaranteed payments from PPA buyers, buyers gained the rights to schedule sales and collect revenues from the market, and consumers received the proceeds from the auction (Pfeifenberger, J. & Spees, K., 2011). Assets not sold in the auction were transferred to the Balancing Pool, a government entity who acted as the buyer and returned market revenues to consumers. An energy-only market means that generation facility owners (GFO's) are not paid for their installed capacity, or its availability, they are paid only for the energy they sell into the market required to meet demand. The energy-only market design also means that capacity and resource adequacy are not guaranteed, but are based on private investment decisions made in response to price signals (MSA, 2010). In addition, a single clearing price is used to settle all transactions in the main energy market[2]. Today, all generators compete to sell energy into the market. New plants are built with private capital, and GFO's are financially at risk for their decisions, including the location, type, size and timing decisions of new assets (AUC, 2012). Although the AUC approves the construction of new projects into the system, the rate of return earned by a GFO is determined by the market and by the decisions of the GFO and their competitors (AUC, 2012).

An energy-only market also means that operating margins must be sufficiently large to recover fixed costs in the long run, which include recovery of capital costs and profits to shareholders (MSA, 2010). Although many generators sell power into the market at variable costs, not all suppliers have the same variable costs. Further, and as will be discussed, some generators offer power into the market below variable costs in order to maintain operational stability[3]. When pool prices are above the variable costs of generators supplying energy, these short-run profits, or inframarginal rents provide generators the operating margins required to recover capital and fixed costs in the long-run (Stoft, S. 2002).

Due to the natural monopoly inherent in the transmission of electricity, it is not as suitable for a competitive market and has remained regulated by the AUC under a cost-of-service model. Customers (load) pay the full costs of operating the system plus a guaranteed and reasonable return to transmission owners (AUC, 2012). Most costs of transmission are borne directly by load, however some costs are allocated to generators, such as interconnection costs and line losses. These are generally recovered through the market and are ultimately borne by consumers. The transmission grid is owned mainly by public companies however it is planned by the AESO. It is the AESO who plans system additions to serve

[2] This system-wide pricing is different from other energy-only markets which use location-based or nodal pricing, requiring generators to pay any additional costs relative to or incurred by their location on the electricity grid.

[3] It is mentioned throughout this paper that suppliers offer into the Energy Market at variable cost, or otherwise offer strategically, either below or above variable cost. This is assumed throughout the analysis even though market power and offers above variable cost are recognized to occur in the Alberta energy market. This assumption does not alter the principles or effects the related analyses are intended to demonstrate.

new load and generation capacity, operates the system in real time, determines charges for using the transmission system, and brings applications for new transmission to the AUC (AUC, 2012).[4]

Electric system reliability refers to the adequacy of the system to supply aggregate demand at all times and the ability to withstand sudden disturbances (AESO, 2012 c, Appendix A). To maintain the reliability of the AIES, production must exactly match consumption at all times. The AESO plans and operates the AIES on a real time basis. Demand, or load, generally acts as a price taker, and will generally pay whatever price the market dictates (MSA, 2010)[5]. This is due to the inelastic nature of electricity demand combined with the transaction costs required to monitor and react to its price. Demand is differentiated by on and off peak requirements. For a given day, on-peak refers to the time period from 07:00 to 23:00 inclusive, Monday through Saturday excluding holidays. Off peak refers to the hours 0:00 to 7:00 and 23:00 to 24:00, Monday through Saturday, all day Sunday and all day on NERC defined holidays (AESO, 2012 c, Appendix C). Since electricity demand is both inelastic and volatile, it is critical that the supply of electricity be able to follow load in order to maintain system balance.

Demand has daily, weekly, and seasonal profiles. Generally, demand is much lower and less volatile during off peak hours and as such, prices too are lower. In addition, demand is variable throughout the year for any given hour, on or off peak. Typically average demand is lower in the spring and fall, somewhat higher in the summer, and highest in the winter (MSA, 2010). Demand can depend on ambient air temperature, time of day, time of year, holidays, day of the week, economic climate, and adjacent markets (ATCO Power, 2010). Availability of supply can also fluctuate. Supply can depend on temperature, inclement weather, time of year, generation unit maintenance outages (planned and unplanned), transmission constraints, economic climate, new generation, decommissioning units, and adjacent markets. With inadequate supply, load shedding or brown outs may occur. With too much supply, the system may become overloaded and require units to curtail output. Because daily and seasonal cycles of load are well understood and fairly predictable, they are anticipated and planned for accordingly, and are not the most important factor driving price (MSA, 2010). Prices can increase because of unplanned or forced unit outages, especially of coal-fired units which serve base load. They can also increase because of transmission constraints or unplanned transmission outages resulting in lower priced power being constrained and requiring more expensive power to be dispatched. High natural gas prices which increase the variable costs of gas generators can also increase prices as these units supply the marginal MW dispatched in many hours (particularly during on-peak hours), (MSA, 2010), (AESO, 2012 c, Appendix C). Prices can decrease when wind generation is high and displaces higher cost gas generation, or when high amounts of base load coal-fired or hydro are available. (AESO, 2012 c, Appendix C). To manage continuous fluctuations in demand and supply, the wholesale electricity market in Alberta is made up of four sub-markets to ensure the reliable delivery of electricity to consumers.

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[4] The coordination of electricity between Alberta and other electricity markets is managed through the Western Electricity Coordinating Council (WECC), a regional body which sets rules and requirements for system operators to maintain in order to ensure the integrity of the overall area. WECC is in place to maintain system stability and coordinate its members. Alberta, British Columbia and over ten western states are part of WECC however different market designs exist throughout and Alberta is unique in its deregulated, energy-only, single clearing price market. Rules and reliability standards are also developed and maintained by the North American Electric Reliability Corporation (NERC) whose authority also exists to ensure system stability. (WECC, 2012)

[5] Load shedding service and demand management contracts exist for a small percentage of load (approximately 2%) to reduce demand however this is limited (MSA, 2010).

These are the Energy Market, the Ancillary Services market, the Dispatch Down Market, and the Forward market (MSA, 2010). Each is briefly described below.

In the Energy Market, or spot market, generators are dispatched on and off the system by the System Controller (AESO) to meet most load requirements. It is the primary market balancing supply and demand. The order by which generators are dispatched to supply electricity is planned the day ahead of delivery by the hourly offers submitted to the AESO by each generator for their power. Offers can be changed up to two hours ahead of delivery after which a Must Offer Must Comply (MOMC) rule applies and generators who do not meet their stated offers will face penalties. Offers are made up of a volume, in MW, and a price. They indicate the amount of power from each generating unit suppliers are willing to provide at a specific price. Generators offer their maximum available capacity in hourly blocks. Each generating unit can offer its maximum capacity in up to seven separate blocks per hour at different volumes and prices. The order by which generators are dispatched is known as the Energy Market Merit-Order (EMMO) and is the offered electricity from suppliers from lowest to highest cost. Wind generation is currently not represented in the EMMO and wind generators are not obligated to submit an offer. Wind generation is considered ‘must-run’ and is effectively offered at $0/MWh. The highest priced unit that is dispatched through the EMMO at any given time is said to be on the margin, and the single market clearing price, known as the System Marginal Price (SMP) is set at the offered price of the marginal unit. This means that the offer price of the marginal MW dispatched sets the SMP. This price is volatile due to constant fluctuations in demand and to the spread between offer prices for blocks of energy by generators. The time weighted average of the SMP’s in each one hour period is known as the Pool Price, and is the price paid to all generators operating during a given hour for all MW they generated, regardless of their original offer price[6]. The lowest price generators can offer their power into the energy market is $0/MWh and the highest, at the price-cap, is $999.99/MWh[7]. How these offers are determined is described later. The price of energy set in this market is used to set or index the prices of energy in each of the other markets.

The Ancillary Services (AS) market is mainly made up of operating reserves required for small fluctuations in supply and demand between offer blocks in the energy market and for contingencies such as unexpected supply shortages due to generator failure or loss of transmission capability. There are two types of operating reserves within the AS market, Active and Standby, where seven different products are sold to the AESO by generators. The Active market consists of four products – Regulating Reserves, Regulating Superpeak Reserves, Spinning Reserves and Supplemental Reserves. Regulating Reserves are procured for small market fluctuations in supply and demand and to maintain reliability between dispatches on the merit curve of the energy market. Regulating Reserves might be used, for example, if wind generation decreased by 10 MW or demand increased by 3 MW (ATCO Power, 2010). Regulating Superpeak Reserves are procured for specific times of the day only, when energy demand peaks. Generating units that offer in Regulating or Regulating Superpeak Reserves must be equipped with specific technology that allows them to be available or otherwise controlled immediately to maintain system stability. Spinning and Supplemental Reserves are used for emergency or unplanned supply

[6] If their offer price was higher than the Pool Price, generators receive uplift payments.

[7] The price cap is intended to curtail market power in a supply shortage event. It should also reflect what consumers would be willing to pay to avoid power interruption, or the value to consumers of lost load. The Alberta price cap however is below reasonable estimates of this value as compared to other markets. (Pfeifenberger, J. & Spees, K. 2011)

shortages. They differ from each other in that Spinning Reserves must be synchronized to the grid, whereas Supplemental Reserves do not. Both however must be made available within ten minutes of being directed on. Regulating, Spinning and Supplemental Reserves are also procured in the Standby market, however these products are used only where the volumes of Active reserves procured are insufficient or fail to become available. One of the key differences between Active and Standby reserves is that, once contracted by the AESO, volumes of Standby reserves can also be offered into other markets until called upon, whereas Active reserves may not be offered into any other markets and must be readily available as operating reserves. This means that prices paid to generators for Active market products must provide sufficient incentive to forgo returns from the energy market.

Active and Standby products are procured differently. For active reserves, the AESO offers generators the opportunity to enter reserves contracts using an index adjusted pool price. The AESO will contract for a pre-determined volume with those generators willing to accept the lowest price for their volumes and will contract with suppliers up until the volume required for that particular reserve product has been met, at which point the price of the marginal MW sets the index and payment (or settlement price) to all contracted suppliers. Each generator supplying active reserves will be paid the pool price plus the index (where the index is usually negative) for each MW supplied per hour. In the Standby Reserves market, a two tiered payment structure exists which consists of a premium and an activation payment. Each generator is paid as offered and there is no marginal bidder setting payments. Generators bid in both their desired premium for being available (whether they are activated or not) and their desired payment for activation should they be dispatched. The AESO stacks offers using a blended price and offers contracts for standby reserves beginning with the least cost offers. It is generally through their activation price that suppliers must weigh their opportunity cost of otherwise supplying in the energy market. Although they can supply in the energy market until called upon as operating reserves, it is possible they could make less than the pool price if activated when pool prices are high[8]. All AS products are procured one day in advance of delivery. (This also gives those who offered but did not enter into contracts for reserves the opportunity to bid in the energy market). The majority of operating reserves/ancillary services are provided by hydro, with most of the remaining requirements provided by gas, although some coal, intertie, and load are used (load is only able to provide supplemental reserves) (AESO, 2012 c, Appendix C).

A third market in which generators can participate is the Dispatch Down Service (DDS) market. This market is much smaller (100-200 MW) and differs from those previously discussed in that offers into this market are not to supply electricity but to withhold it. This market was established in 2007 to offset the price-depressing effects on the pool price of requiring certain generators to run outside the energy market due to ongoing transmission constraints in certain locations. The need to maintain system reliability in congested areas, which are limited by transmission, requires that certain generators run when they would not normally choose to do so or it is not efficient for them to do so. Transmission Must Run (TMR) requires certain units to run regardless of whether or not they have been dispatched based on their offer price. Gas-fired units are the predominant provider of DDS, receiving 75% of the dispatches in 2010 (AESO, 2012 c, Appendix C). The remainder is provided by coal with some hydro.

[8] For example, a $10 premium and $50 activation payment would result in a gain to the generator when the pool price is $25 but result in a loss if the pool price was $400.

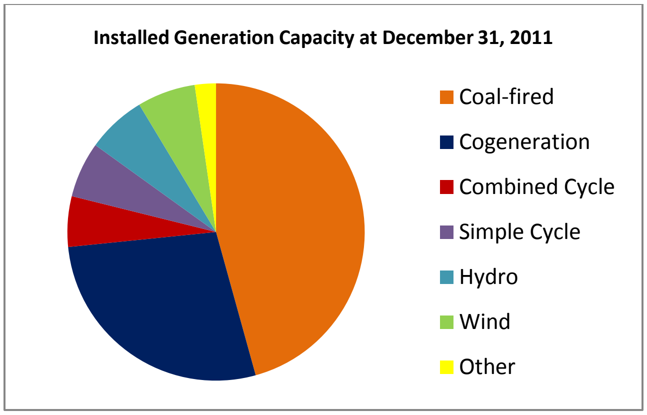
The forward market is the last sub-market in the wholesale electricity market. In this market, contracts for the supply of energy are made between buyers and sellers ahead of production and consumption (MSA, 2010). An agreed upon price for a contract period is determined between the generator and end user outside the Power Pool. Energy is not bought or sold on a real-time basis however it is still produced and consumed on a real-time basis and the AESO still manages the physical flow of electricity (MSA, 2010).

Outside the Alberta wholesale electricity market, electricity can also be imported or exported via interties connected with British Columbia or Saskatchewan. Alberta typically imports generation during on-peak hours (high demand) and exports during off peak hours (low demand) (ATCO Power, 2010). The transmission capacity utilized on the BC tie-line is less than its design rated capacity due to congestion on the intra-Alberta transmission system (AESO, 2012 c, Appendix I). This tie line has a rated capacity of 1200 MW for imports and 1000 MW for exports however a maximum Available Transfer Capacity (ATC) of 650 MW for imports and 735 MW for exports. The Saskatchewan tie line has a rated capacity of 150 MW and currently imports/exports up to this capacity (Pfeifenberger, J. & Spees, K. 2011). ATC is the capacity in any given hour available to be transferred across the tie-line and can depend on area voltages, ambient temperatures, adjacent line flows, capacity reservations, and contingency plans (ATCO Power, 2010). The price spread between the Alberta and neighbouring markets will determine the direction in which it is profitable to flow power. When the pool price in Alberta is higher than neighbouring markets, it is profitable to import electricity, and when it is lower, it is profitable to export. One potential arbitrage opportunity for BC is with their hydro storage capability (MSA, 2010). BC is well positioned to export electricity into Alberta during peak demand times and import cheaper power from Alberta during non-peak times, particularly when pool prices are low at night and when wind supply is available (MSA, 2010). A third 300 MW tie-line with Montana is in the process of being built which could increase import and export capacity and provide a new source of import/export opportunities for Alberta. This tie-line is expected to be used mainly to transfer wind energy between areas (MSA, 2010). Additional import/export capabilities can have varying effects on the market.

In addition to the supply required to meet expected demand, the market accounts for reserve margins in the event of supply shortages or unexpectedly high demand. Lower reserve margins are a signal that supply is limited and investment in new generation capacity is warranted to increase supply. Higher reserve margins are a signal there is a surplus of supply and that the market has overbuilt capacity and new investment may not be profitable. A 15% reserve margin is used by the AESO in their 2012 Long Term Outlook. Since 2002, reserve margins in Alberta have ranged from 14% to 25% (without interties) (AESO, 2012 a). Effective Reserve Margin is the amount of generation installed above peak load net of retirements and de-rating wind and hydro (AESO, 2012 b).

2.2 Alberta Generation and Capacity Mix

Coal fired generation currently provides the majority of the energy required by Alberta's market. As of December 31, 2011, Alberta had the capacity to generate 13659 MW. Of this installed capacity, 46% was coal, 39% gas, 6% hydro, 6% wind and 2 % other, where of the gas generation 28% was from Cogeneration, 5% Combined Cycle Gas Turbines (CCGT), and 6% Simple Cycle Gas Turbines (SCGT). Although only 46% of installed capacity, coal fired generators supplied 67% of energy to the market that year. Gas and cogeneration accounted for 19% of energy supplied, wind for 4%, and hydro for 3.4% (AESO, 2012 a).



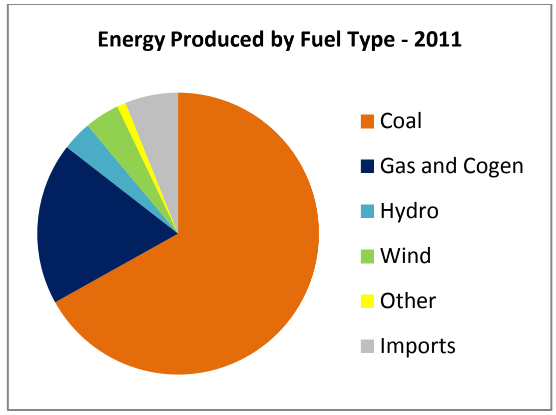


Figure 1: Installed generation and energy produced - 2011

Coal has traditionally provided a high level of generation but it is unlikely that much new investment in coal will occur due to its high capital costs and increasing variable costs from recent or potential environmental regulations (these will be discussed later). Gas and cogen produced 3,068 GWh more in 2011 than were produced in 2002, however their ouptut has fluctuated throughout (AESO, 2012 a). Wind and hydro currently make up 13% of generation (12% at the end of 2011) and provide a much higher proportion of energy relative to their respective installed capacities. These forms of generation however rely on less reliable fuel sources. Water is generally not available to run hydroelectric plants at full capacity and wind is intermittent and can only be used when the wind blows. Currently, most wind is located in the south of the province, most coal is located in the centre, and most hydro in the south west. Gas is much more flexible in location due to the large pipeline infrastructure throughout the province.

The various generation types offer or enter into the Energy Market quite differently and supply different characteristics of load. As noted earlier, generators may offer in their energy at any price between $0/MWh and $999.99/MWh. Offers are generally made to recover variable costs, however strategic offers may also be made to ensure some plants are always being dispatched, and others not generating unless absolutely required. Most supply comes from base load plants which are generally always dispatched unless operationally unavailable. Power from these plants is either fully or partially offered into the market at $0/MWh for operational reasons. These plants generally have dispatch limitations due to minimum required output for the maintenance of safe, efficient or stable operations (coal), (ATCO Power, 2010). Limitations from fuel sources (wind) or requirements to provide steam to host plants (cogeneration) are also offered at $0/MWh and are considered Must-Run[9]. Coal plants, which currently provide the majority of base load supply, are not operationally designed or otherwise capable of being continuously ramped up or down or handle frequent fluctuations in output. To ensure they are always dispatched, at least at their minimum efficient level of output (which is approximately 40% of maximum capacity), these generators will offer at least some energy into the energy market at $0/MWh. [10]Generally, base load plants recover capital costs when pool prices are higher than variable costs, and are willing to earn less than variable cost when pool prices are low to ensure operational efficiency and limit wear and

[9] Base load may be defined commercially or operationally. Cogen and wind are considered base load for commercial reasons.

[10] A sample 300 MW coal plant might offer in 120MW at $0/MWh, 80 MW at $20/MWh, 50 MW at $50/MWh and the last 50 MW at $250/MWh.

tear. Base load plants generally have high fixed costs per kW of installed capacity and low variable costs making it efficient to run more often. With offers mainly at $0/MWh, base load plants are generally price takers.

Mid-merit plants, which often set price, are mainly the higher priced segments of coal plant capacity (which can be more easily ramped up and down), and the output from combined-cycle gas-fired generators. These volumes are not required to maintain minimum load or site processes, or may be excess capacity above operational or stability limitations or cogeneration requirements (ATCO Power, 2010). The types of plants that offer mid-merit can be more easily dispatched which makes them ideal for meeting the fluctuations in demand (or supply) to maintain system reliability. These plants or partial plant volumes must also be able to frequently, reliably and operationally be dispatched up and down. These plants generally offer in at their variable costs of production (recovering such costs as fuel, operations and maintenance) and set the SMP much of the time (AESO, 2012 a)[11]. Gas-fired units are typically the marginal units dispatched during on-peak hours when demand is higher (AESO, 2012 c, Appendix C). The offer prices of gas fired generation typically fluctuate with the price of natural gas.

Peaker plants are dispatched for relatively few hours per year and are used to meet peak demand when needed (usually due to system constraints and when demand is higher). Peaker plants are typically simple cycle gas plants and have low capital costs per kW of installed capacity and high variable costs. This can be because they are older plants and often inefficient (Green, 2006 p. 22) however some of Alberta's newest technology assets are simple cycle gas turbines (Cloverbar and Crossfield plants). These plants are typically small and can more easily ramp up or down than other asset types. With low capital cost recovery requirements and high variable costs, peaker plants can be expected only to be willing to run when demand is very high and as such, will offer energy only into the market at relatively high prices. Their higher prices usually reflect their emergency use or higher variable costs incurred in the event they are needed to generate. These prices also provide the scarcity rent/inframarginal rent required by other GFO's to recover their capital and fixed costs in the long run.

The optimal amount of each generation type in the market can be assessed using load duration and average cost of energy curves. Figure 2.1 shows the load duration curve for Alberta for the year 2011, derived from hourly load data and demonstrates the percent of time in 2011 when demand reached a given level. The peak load can be seen at the intercept on the y-axis. In Alberta, in 2011, the peak load was 10226 MW and the minimum load was 6459 MW. Load did not fall below this level in any of the 8760 hours for the year. Years 2008, 2009 and 2010 are also drawn to demonstrate the consistency of the load profile. The screening curve in Figure 2.2 reflects the average cost of energy of each technology type. The average cost per MWh of energy of serving load is plotted as a function of the number of hours per year that plant will be used[12]. The costs of energy supplied vary depending on the amount of time per year the plant operates. The average cost of energy for different plant types depends on the number of hours per year that the plant operates. Where one type of technology is the lowest cost, it can be assigned to serve that portion of the load duration curve. These graphs can demonstrate how much capacity should be served with peakers, mid-merit or base load plants and guide investment decisions by using them to determine the technology that minimizes the average cost of energy (Stoft, S. 2002). The effects of wind on the generation mix will be discussed in this way in the section 3.3. In theory, in the short run, if there

[11] Gas-fired units set price 49% and 46% of the time in 2010 and 2011, respectively (AESO, 2012 a)
[12] This model is based on discussion with ATCO Power subject matter experts

is too much base load generation, pool prices may be and remain low. If there are too many peakers, pool prices may be high. In the long run, new investment would occur in response to price signals to install the appropriate types of assets and the optimal generation mix would exist.

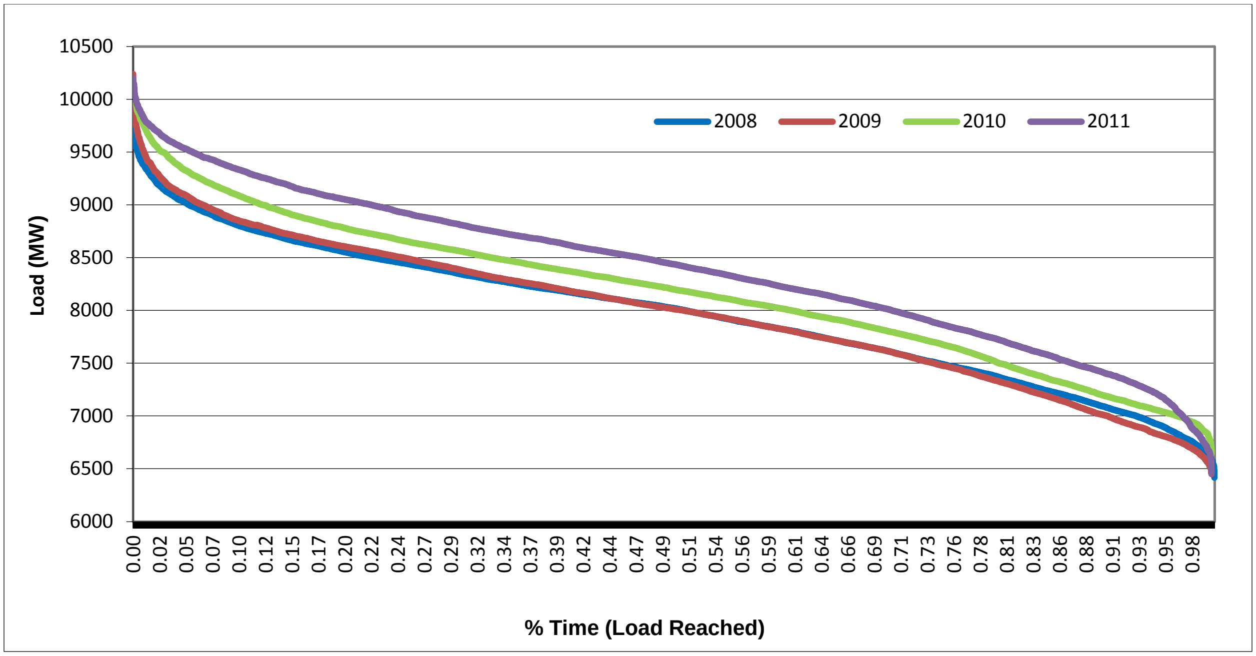


Figure 2.1: Load Duration Curve for Alberta based on hourly demand for each of 2011, 2010, 2009 and 2008

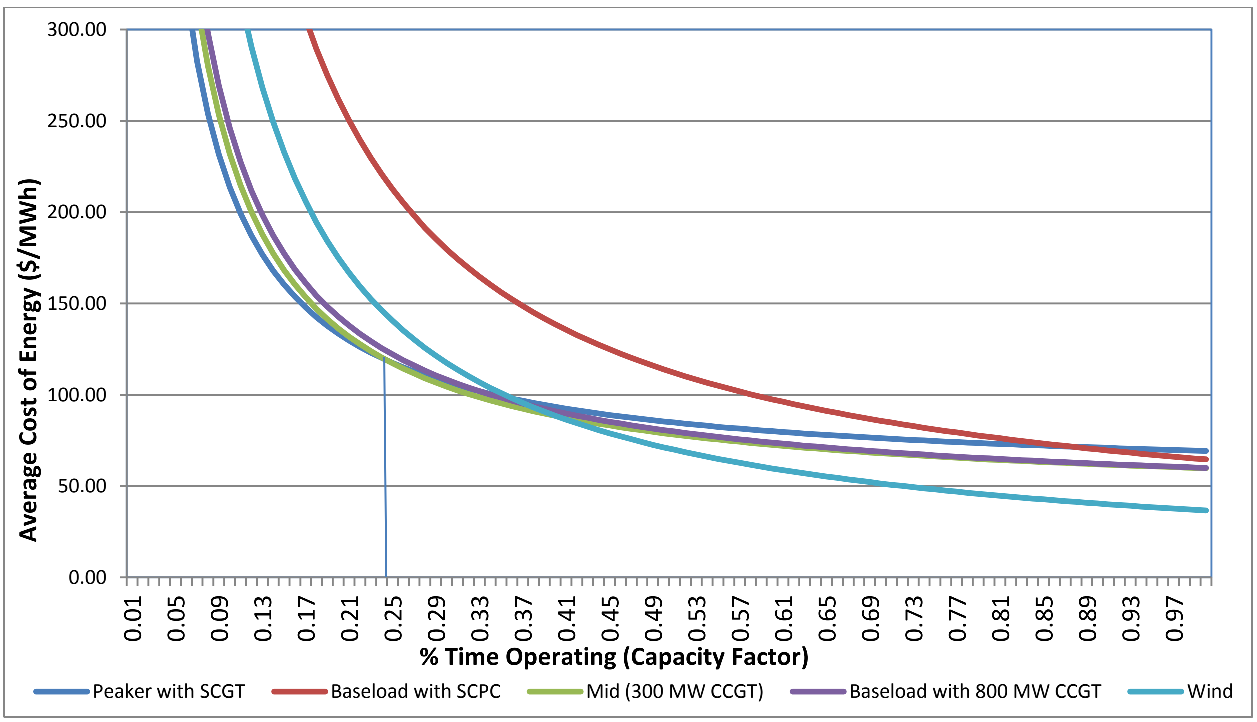


Figure 2.2: Average Cost of Energy Curves for Alberta based on 2011 cost data.

The average cost of energy for three types of gas-fired generation (simple cycle, 300 MW CCGT and 800 MW CCGT), super critical pulverized coal, and wind are provided in the Figure 2.2. These curves are calculated using the following equation:

Average Cost of Energy = Fixed Costs/Capacity Factor + Variable Costs (Stoft, S. 2002)

Capital Costs and Fixed O&M costs are converted to \$/MWh so these costs can be summed. A discount rate of 10% was used to convert Capital Costs to \$/MWh[13]. Fixed O&M costs in \$/kWy (dollars per kilowatt year) were converted to \$/MWh by multiplying by 1000 and dividing by 8760 hours. A gas price of \$5.00/GJ was multiplied by the technology's Heat Rate to calculate Variable Fuel cost[14]. Table 1 summarizes these costs. Values in white headings were taken from the AESO 2012 Long Term Outlook Appendix H Comparative Generation Costs.

Table 1: Inputs for Average Cost of Energy Curves

Technology	Capacity (MW)	Capital Cost (\$/kW)	Capital Component (\$/MWh)[15]	Fixed O&M (\$/kWy)	Fixed O&M (\$/MWh)	Variable O&M (\$/MWh)	Variable Fuel (\$/MWh)	Heat Rate (GJ/MWh)	Project Life Time (Yrs)
Wind	150	\$2,300	\$28.93	\$50.00	\$5.71	\$2.00	\$0.00	0	25
Supercritical Pulverized Coal (BF)	450	\$3,850	\$45.57	\$33.00	\$3.77	\$6.30	\$9.00	9.4	35
Gas Combined Cycle	300	\$1,435	\$17.38	\$15.50	\$1.77	\$3.70	\$37.00	7.4	30
Gas Combined Cycle	800	\$1,625	\$19.68	\$9.00	\$1.03	\$3.30	\$36.00	7.2	30
Gas Simple Cycle	100	\$1,150	\$14.46	\$14.00	\$1.60	\$4.30	\$49.00	9.8	25

Wind is included in the graph to demonstrate that at a capacity factor of 41% or higher, under these inputs, wind is seen as the least cost technology to serve load (here, base load). However, wind does not see this capacity factor on average and this would require the assumption that wind was firm (i.e. consistently available) and did not create issues in the system relating to its volatility.

These results are highly dependent on the price of natural gas however gas-fired generation is currently seen to be the most efficient investment because it has the lowest average cost of energy. This can be seen by looking at curves which represent the lowest costs in Figure 2.2 SCGT and CCGT are the least cost technologies when accounting for the capacity factor of wind. The analysis presented suggests that any gas price under approximately \$5.50/GJ, where the average cost of energy for coal would become lower than all gas-fired generation technologies, would not make any investment in supercritical pulverized coal efficient and suggests investment in base load would be mainly in CCGT[16]. The optimal energy supply mix based on current costs of development (2011 \$CAD) and 2011 load is to serve up to 76% of load

[13] These costs were amortized over the life of the plant using the following equation from Stoft, S. (2002): Amortized capital cost = (r x overnight cost)/$(1-1/(1+r)^T)$ where r is the discount rate and T is the Project Life Time

[14] Sproule natural gas price forecast projects \$5.50 and \$5.53 for 2017 and 2022 (AECO-C Spot Price in constant prices) (Sproule, 2012)

[15] This input is used only in the amortization of capital cost for the purposes of calculating the Average Cost of Energy

[16] Gas prices of \$3.50/GJ and \$8.00/GJ are modeled in Appendix G.

with CCGT and the top 24% of load with SCGT, where it is the lowest cost technology[17]. This can be seen at the point which peaking capacity becomes cheaper than CCGT in Figure 2.2, at 24%. Up to this point (i.e. for 76% of time), CCGT can be seen to be the cheapest reliable technology. For the purposes of this model, cogeneration[18] and hydroelectric generation costs are not included. Due to its volatility, for the remainder of this paper wind will be considered negative load. Negative load refers to subtracting wind generation from actual load and treating the resulting net load in a conventional manner when constructing a load duration curve (Davitian, 1978). This ultimately acts to reduce load and affect the optimal generation mix.

As noted, these curves can demonstrate the optimal mix of generation moving forward based on the cost of investment today (Stoft, S. 2002). This analysis suggests that investment in base load capacity should be in gas-fired technology, predominantly CCGT and that smaller sized CCGT are marginally cheaper than larger CCGT, especially at higher capacity factors when CCGT is optimal. For the purposes of this analysis, they will both be considered equivalently capable of serving base and mid-merit load. Coal-fired generation, which serves most current base load, is no longer an efficient investment at current and forecasted gas prices and emissions regulations. This suggests that as most coal plants retire in the next 10 years due to 50 year life, replacement base load will be met by CCGT. As such, investment in wind will be assessed relative to investment in CCGT (and SCGT) for the remainder of this paper.

2.3 Long Term Forecast

The long term load forecast prepared by the AESO is based on growth in each of GDP, population, and oilsands production. Their generation forecast was developed by assessing the incremental generation required to meet forecasted load growth and expected generation retirements, considering available resources and comparative costs (AESO, 2012 b)[19]. This paper will take the load forecasts developed in the AESO 2012 Long Term Outlook as given, and as noted in the previous section will assume gas-fired technology to currently be the most economically efficient investment in new generation. The forecast is identified and briefly discussed to demonstrate the need for additional generation and later assess the efficiency and impacts of additional wind capacity to meet demand, relative to gas. Factors affecting uncertainty in the forecast follow.

Figure 3 shows the long term load outlook using winter peak for Alberta Internal Load[20]. Existing installed capacity is identified and shown to decline while the expected effective capacity required to meet load, including the 15% reserve margin, is shown to increase up to 19873 MW by 2032. Load at winter peak is expected to grow from 10609 MW at the end of 2011 to 17281 MW by 2032 (AESO, 2012 b, Appendix E). Details of the 2017, 2022 and 2032 forecast can be found in Appendix H. The decline in existing capacity is most noticeably a reduction of installed capacity from coal plants. This decline is the

[17] The average cost of energy curves showed 300 MW and 800 MW CCGT with marginally different $/MWh and this paper will assume either can be used to serve base load and mid-merit generation. Wind cannot currently sustain a capacity factor above the 41% required to make it an optimal technology in the generation mix and is variable in output which is not considered by the results shown.

[18] Approximately **70%** of cogeneration typically serves site load and the remainder is offered to the market (Discussion with ATCO Power personnel).

[19] Details on the AESO assumptions in developing these forecasts can be found in their report.

[20] Alberta Internal Load is defined as total electricity consumption, including behind-the-fence, the City of Medicine Hat, and losses (transmission and distribution) (AESO, 2012 b, Appendix A)

result of a combination of several factors including plants reaching a 50 year life, PPA expiration, and the very likely prohibitively high costs of running current coal plants following the emissions reduction regulation (see section 2.4).

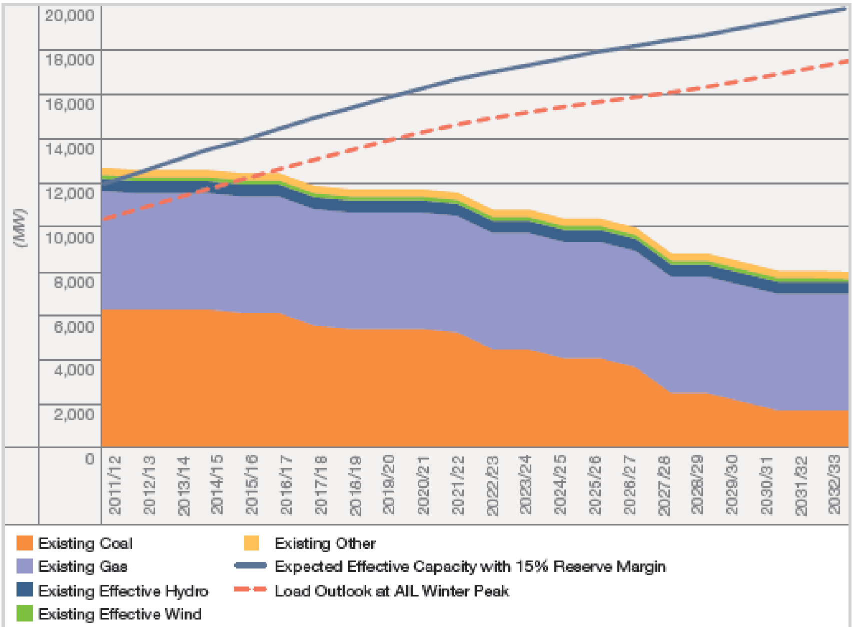
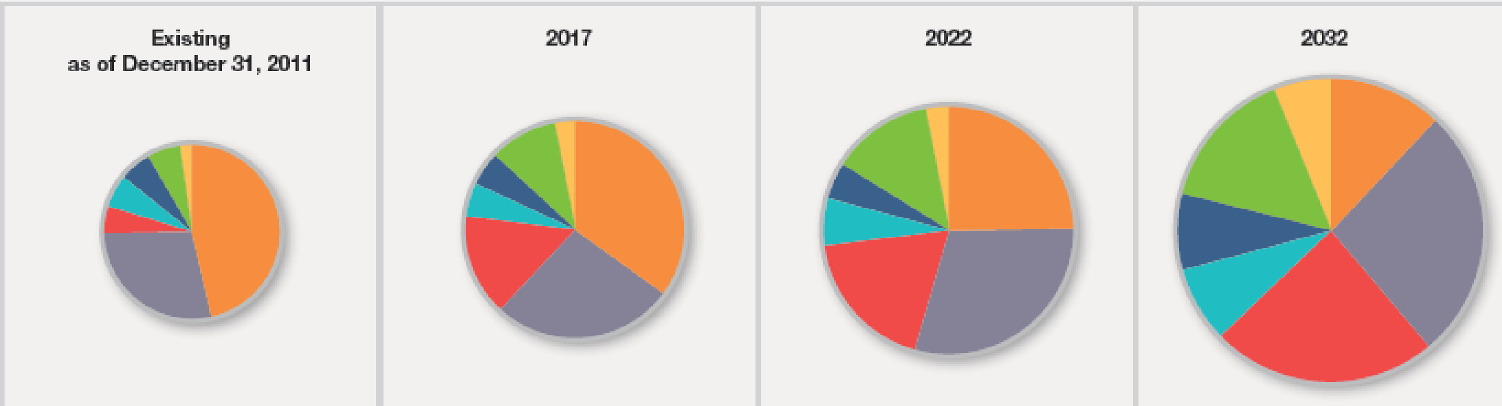


Figure 3: Expected Generation Capacity Requirements and Load Outlook *(Source: AESO 2012 Long Term Outlook, (AESO, 2012 b))*

Gas fired generation is projected to be the largest and fastest growing source of generation to meet growing demand, as shown in Figure 4, with a sizeable increase in CCGT specifically. Gas-fired generation is projected to grow from 39% of installed capacity in 2011 to 59% by 2032, (rising to 47% by 2017 and 55% by 2022). As noted earlier, gas-fired generation can reliably provide base load, mid-merit and peaking capacity and provides higher capacity value to the system as a flexible technology. Additional factors making gas-fired generation attractive are projected stable natural gas prices, availability of fuel supply, competitive capital costs, and relatively low GHG risk when compared to coal (AESO, 2012 b). Fast ramping gas-fired generation will also become more attractive with increasing wind capacity, which is expected to increase from 6% at the end of 2011 (7% today), to 10% by 2017 and up to 15% by 2032.



Type	Existing as of December 31, 2011		2017		2022		2032	
Coal	46%	6,242	35%	5,900	25%	4,832	12%	2,876
Cogeneration	28%	3,782	27%	4,619	30%	5,770	27%	6,365
Combined Cycle	5%	750	15%	2,518	19%	3,668	24%	5,568
Simple Cycle	6%	827	5%	901	6%	1,176	8%	1,826
Hydro	6%	879	5%	879	5%	979	8%	1,979
Wind	6%	865	10%	1,694	13%	2,544	15%	3,578
Other	2%	314	3%	445	3%	585	6%	1,385
Total		13,659		16,956		19,554		23,577

Figure 4: Long Term Generation Forecast – Summary of supply/generation mix forecast *(Source: AESO 2012 Long Term Outlook (AESO, 2012 b))*

In general, the 2012 LTO by the AESO projects peak demand to grow annually at a rate of 3.1% from 2011 to 2022, and an overall forecast of 2.4% annual growth to 2032. The Brattle Group Long Term Adequacy Study for Alberta also notes that "the rate of plant retirement will most likely average 220 MW per year [for the next 20 years], which is 1.5 times the 150 MW of annual retirements experienced during the last decade as well as the anticipated load growth of 3.2% per year and an associated reserve margin requirement increase would require the addition of 740 MW per year over the next 20 years, almost twice the rate of historic generation additions, which averaged 380 MW over the past decade" (Pfeifenberger, J. & Spees, K. 2011). They also project that future market prices strongly favor a shift from coal generation to gas fired plants due to greater flexibility in meeting different characteristics of load and lower capital costs, as also demonstrated in Figure 4. They suggest that additional wind, and coal with Carbon Capture and Storage (CCS) may be supported by government policy (Pfeifenberger, J. & Spees, K. 2011).

The forecast developed by the AESO was developed recognizing the challenges and uncertainty faced by the Alberta electricity market. These include the volatility of natural gas prices, the expiration of PPA's and effects on potential plant retirements (and transitional reliability concerns), the high dependence on coal (particularly serving base load) under a federal coal retirement mandate, other current and pending environmental legislation, the impacts of additional wind, and the role of interties (Pfeifenberger, J. & Spees, K. 2011). Alberta is also a relatively small market with limited participants and is surrounded by non-market based (i.e. regulated) regions (Pfeifenberger, J. & Spees, K. 2011). Additional risk or other factors that could affect the long term forecast include market rule changes, technology improvements (particularly wind turbine and energy storage technology), transmission delays or constraints, and changes in public policy or legislation to promote clean or renewable energy. Several of these factors are discussed briefly below. Legislation and public policy are discussed in more detail in the next section.

Natural gas prices have a close relationship to pool price as gas-fired generators are price-setting suppliers in many hours, particularly on-peak hours. As natural gas prices fluctuate, so do variable production costs and pool prices. Gas prices between 2002 and 2011 have been very volatile, seeing a low of just above $2/GJ and a high of just below $12/GJ (Pfeifenberger, J. & Spees, K. 2011). Gas prices are currently relatively low and have been projected to remain low for the foreseeable future due to the increased availability from developments in shale gas production (Pfeifenberger, J. & Spees, K. 2011)[21]. A higher gas price is not forecast however a shortage of available gas due to a US coal moratorium or fracking regulation may alter the current gas price forecast and would have a large effect on the optimal mix of generation technologies in the market[22].

The decline in coal fired generation noted in Figure 3 can be attributed to the end-of-life of currently installed coal plants, the economic viability of operating these units without PPA payments after expiration leading to their early retirement, and to recent or pending regulation making new coal prohibitively expensive. Whether owners of coal-fired units will choose to operate after PPA expiration will depend on whether they will be able to recover their capital and fixed costs without PPA payments and whether new capital costs will be required to meet retrofit requirements under GHG emissions legislation (discussed in section 2.4). If investments needed to maintain or retrofit units cannot be recovered without PPA payments or from generating revenues, continued operation past PPA expirations may not be economically efficient. Retirement decisions may also be affected by payments for decommissioning costs available to those units which apply to be decommissioned within one year of PPA expiration. Those that operate after their PPA expiration will not be entitled to these payments and may change operation decisions for those units not planning to run for much longer after the expiration of their PPA (Pfeifenberger, J. & Spees, K. 2011). Units likely to retire shortly after PPA expiration due to environmental regulations may find it more efficient to retire upon PPA expiration and be eligible to receive decommissioning payments (Pfeifenberger, J. & Spees, K. 2011). Low gas prices and additional wind may also keep pool prices low and not allow for the operating margins required by coal-fired generators to recover fixed costs without PPA payments. Additional wind generation setting more frequent pool prices of $0/MWh and requiring coal-fired generators to operate at minimum output levels will further create challenges for coal-fired units. This might force early retirement for some units or add to the incentives for retiring upon PPA expiration.

A further element of uncertainty comes from a large proportion of the scheduled PPA expirations occurring at or around the same time. The quantity of simultaneous PPA expirations may represent approximately 28% of capacity in 2020 (Pfeifenberger, J. & Spees, K. 2011). Lack of coordination between retirement and online dates of individual units may cause transitional reliability concerns and pool price spikes (Pfeifenberger, J. & Spees, K. 2011). Timing to build new plants must be factored into new investment decisions to ensure such transitional issues do not arise. Gas-fired generation can typically be developed in under three to five years and wind plants two to three years (AESO, 2012 b). Transmission infrastructure must also be coordinated or already in place at sufficient capacity to ensure that coal plant retirements do not shock the system.

[21] Sproule natural gas price forecast projects $5.50 and $5.53 for 2017 and 2022 (AECO-C Spot Price in constant prices) (Sproule, 2012)
[22] Based on discussion with ATCO Power subject matter expert.

2.4 Public Policy and Regulatory Requirements[23]

The choice of generation technology to meet load growth will also be affected by political and regulatory uncertainty. The public policies implemented by federal, provincial and even international governments can have a direct or indirect effect on the relative costs of different generation technologies. Existing federal, provincial and international programs affect the relative costs of wind energy by providing either incentives for wind energy development or disincentives for generation from alternate technologies, thereby increasing the relative attractiveness of wind. The desired effect or stated goal of most renewable energy policies is the reduction of carbon emissions or other pollutants. Their actual impacts can vary depending on the specific target of the policy, how effectively the chosen policy is implemented, as well as how inherently efficient that policy may be. The effects of subsidies, Renewable Energy Credits and carbon pricing will be discussed in section 6 however several other current and pending regulations are important for current investment decisions.

The most recent federal wind subsidy program, ecoENERGY for Renewable Power Program, expired in March, 2011. Under this program, eligible wind generation projects commissioned between April 1, 2007 and March 31, 2011 received a subsidy of $10/MWh of generation for up to the first 10 years of their operation (IEA, 2012 a). Prior to this, the federal government provided these financial incentives under the Wind Power Production Incentive (WPPI), in place between April 1, 2002 and March 31, 2007 and which was rolled into the updated ecoENERGY Program (IEA, 2012 b). There are currently no federal incentive programs that directly apply to the development of wind power.

Existing federal tax law also provides incentives for renewable energy generation, including wind, by making it more financially attractive. Under Part XI Capital Cost Allowance (CCA) of the federal *Income Tax Regulations* (under the *Income Tax Act)*, deductions of a given percentage of the undepreciated capital cost (as of the end of the taxation year) are allowed (NRC, 2012). This percent is determined by the applicable asset class in Schedule II of the Regulations. Wind turbines fall under Class 43.1(d)(v) and as such meet the requirement for Class 43.2, for which accelerated capital cost deductions of 50% may be claimed on a declining balance basis. The benefit of accelerated depreciation is that it allows larger deductions earlier in the life of an asset and can thereby offer overall cost reductions. In addition, Canadian Renewable and Conservation Expenses (CRCE) can be fully deducted under section 1219 (1)-(4) of the *Income Tax Regulations*. This would include expenses incurred during the development and start-up of wind development projects for which at least 50 per cent of the cost of depreciable assets relates to equipment eligible for Class 43.1 or Class 43.2 CCA treatment (NRC, 2012). This subsidy, is however, relatively negligible.

Federal legislation is in place or pending that may affect the price of alternate technologies thereby indirectly making wind power more desirable. The final *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (under the *Canadian Environmental Protection Act*) was published in the Canada Gazette Part II on September 12, 2012. Separate parts of this regulation come into force in 2013, 2015 and 2030. As mentioned earlier, this regulation sets performance standards for new and existing coal-fired units to meet prescribed emissions intensities. To meet these targets, the levelized cost of electricity for coal-fired generation will rise and will effectively result in either a CCS

[23] This section is a revision of School of Public Policy, PPOL 617 Independent Assignment submission April 11, 2012

retrofit or retirement of the unit (Pfeifenberger, J. & Spees, K. 2011)[24]. The regulation requires coal plants to meet the same standards as higher efficiency gas plants or else retire after the end of their useful life identified at 50 years (in most cases)[25]. Legislation relating to the Base Level Industrial Emissions Requirements of Criteria Air Contaminants is pending which would require the installation of emissions reduction equipment on new and existing generation units, potentially as early as 2013. This work is ongoing under the collaborative Comprehensive Air Management System framework and will likely be implemented under the *Canadian Environmental Protection Act*, however other regulatory frameworks are being explored. This could add a cost of over to $200 million per generation unit for certain technologies (BLIERS Sector Expert Group, 2012 p.72).

There are currently no provincial targets or incentive programs for renewable energy generation within Alberta. The Clean Air Strategic Alliance, which provides policy advice to the Government of Alberta, has developed a framework to manage air emissions from the electricity sector in Alberta. Their recommendations will affect the cost of non-renewable generation technologies and have been adopted in the form of legislation. This legislation includes the *Emissions Trading Regulation* (under the *Environmental Protection and Enhancement Act*), which requires existing generating units to meet baseline emission intensities until the end of their design life (40 years or the end of Power Purchase Agreements), at which point they must be retrofitted to meet new technology requirements or be shut down (BLIERS Sector Expert Group, 2012). Tradable emissions credits are also granted for units that operate below their baseline emission requirements, which may be used to meet the new emissions standards. This regulation will have significant effects on the cost of operating certain generation technologies, including gas, and may make wind power more attractive. Timing to comply is based on individual units.

The Alberta *Specified Gas Emitters Regulation* (under the *Climate Change and Emissions Management Act*) is also in place setting emissions intensity limits for prescribed gases but has less significant effects on the costs of alternate technologies. Generators outputting more than 100,000 tonnes of CO_2 per year must reduce emissions by 12% per year below 2003-2005 baseline output. To comply, generators can improve efficiency, contribute $15/tonne of CO_2e to invest in emissions reductions projects, purchase offset credits from other projects such as renewable energy projects, or performance credits from those who exceeded their 12% GHG reduction target (Pfeifenberger, J. & Spees, K. 2011). As of 2009, there were approximately 4090 MW of gas and 6060 MW of coal plants subject to this regulation (Pfeifenberger, J. & Spees, K. 2011). The limited plant output covered by this regulation (12%) and the small increases in variable costs – that will ultimately be passed on to consumers limit the effects of this regulation on relative costs of alternate technologies. The current design is due for review in 2014.

Under its Public Utilities Code, California's Renewables Portfolio Standard (RPS) program was established and currently requires California electric utilities to procure 33% of their total portfolio from eligible renewable energy resources by 2020 (CPUC, 2012 a). The California Public Utilities Commission (CPUC) has in recent years allowed long term contracts with other utilities, including out-of-state utilities to purchase Renewable Energy Credits (REC's) to fulfill a maximum of 25% of their renewable energy requirements (CPUC, 2012 b). This has helped reduce the effective cost of wind power development in

[24] Alberta has invested $2 billion in clean coal and CCS technology. At least two projects are currently underway (AESO, 2012 b)

[25] Based on internal memo from ATCO Power

Alberta for those utilities that have sold these REC's. Recently, these contracts have been limited in duration which has reduced the subsidy these REC's provide to those who offer them, however future changes to the CPUC rules for the RPS framework could have a significant effect on the cost of new wind development in Alberta.

Environmental issues and climate change are increasingly creating pressure on politicians and government to adopt methods for reducing green house gases and other pollutants and rely more on renewable sources of electricity. The decisions of those responsible may have a direct impact on the development of new wind power development in Alberta. This can include new legislation and regulations to reduce GHG's, changes to California's legislated RPS program or the creation of such programs in other jurisdictions, the coming into force of several pending environmental regulations, any new federal (or provincial) subsidies for wind generation, and the repeal of any current laws or programs in place. These policies and requirements will also indirectly affect the entire system, potentially adding costs or raising prices elsewhere to ensure reliability. Whether the objectives of policy and private investment will conflict with an efficient and reliable electricity system will be analyzed in section 6.

3.0 WIND ENERGY IN ALBERTA

3.1 Overview

There are currently 15 wind farms in Alberta connected to the AIES which have an aggregate installed capacity of 939 MW (865 MW at the end of 2011)[26]. Current wind resources are primarily located in the south west of the province and as will be discussed in section 3.2, the majority of current wind farms have highly correlated wind resources and thus generation output[27]. The AESO Project List (identifying wind projects in the process of gaining power plant approval from the AUC) shows that as of June 2012, twenty-eight wind plants were in the queue for development[28] although not all will necessarily be built (AESO, 2012 d). Of these, at least 12 are proposed to be built in the south east and centre east of the province, away from most current wind plants, which will have an effect on the degree of correlation. Figure 5 shows geographic wind resources in the province, current wind power generation, and potential sites for wind development.

Wind power is generated unevenly in response to wind conditions and when it is available, it displaces the output of other generators. In general, wind is more valuable to the electricity system if it is generated during the daytime to serve load peaks when the market would otherwise experience higher variable costs per MW generated. In Alberta, wind does blow more during on-peak hours, which increases its value. However, because wind blows intermittently and at variable speeds, it is less reliable than conventional generation and reduces the value of generation capacity from wind to the system operator.

[26] See Appendix A for a list of these plants, their rated capacities, and their installation dates.
[27] This has the effect of aggregate wind energy tending to be supplied in similar relative volumes across generating plants and can increase the volatility of wind generation.
[28] At least stage 2

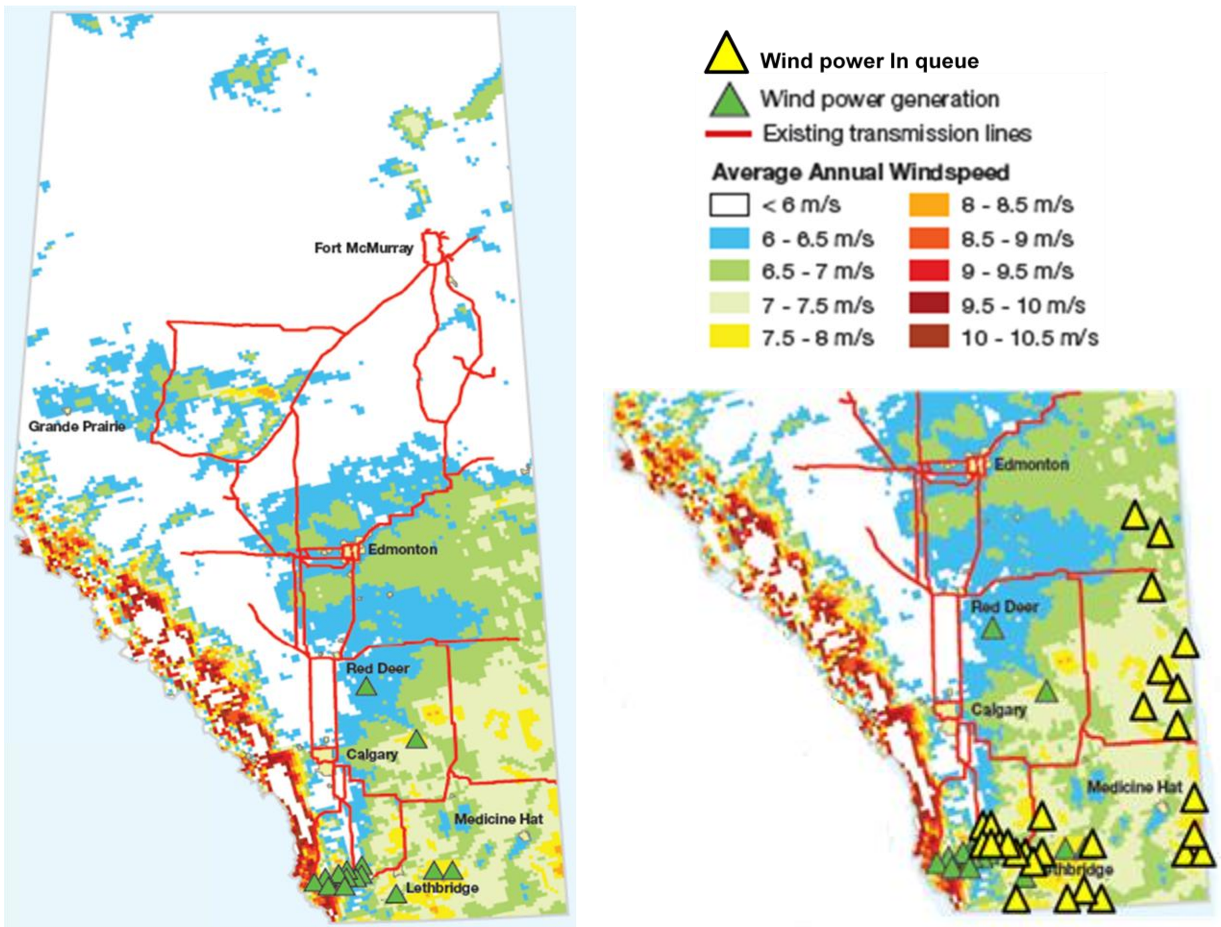


Figure 5: Geographic location of wind resources

Source: Left side map taken from 2012 AESO Long Term Outlook (AESO, 2012 b). Wind power in queue added to AESO map based on AESO Project List (AESO, 2012 d) and estimated locations from assessment of planning areas

There are three major issues with wind generation in Alberta: its intermittency, its volatility, and its location. Each of these issues has an effect on the ability of wind generators to generate electricity and each imposes costs on the electricity system. In Alberta, the location of current wind generation poses reliability issues because it is mainly located in the south west. This is discussed in section 3.2. The location of wind resources also imposes costs of bulk transmission which are required to reach wind plants that are further away from load. This will be discussed in section 4.3.

The intermittency and volatility of wind and the lack of economically viable energy storage technology create operational challenges and reliability concerns when wind generation is added to the electricity system. Because wind generators are limited by the wind resource, they cannot choose when to generate. This can require back-up generation capacity in the market as well as reserves or other services to manage volatility in their output. The intermittency of wind also results in a lower capacity factor for wind generators because, although available to generate, wind generation capacity cannot generate without wind. Capacity factor refers to the actual generation output from a plant divided by the maximum rated output of that plant. This means that wind capacity sits idle for much of the time while capital and fixed operating and maintenance costs must be paid. Wind plants in Alberta have seen a range of average annual capacity factors. Since 2007, the high has been 40.5% and the low 27.9% (AESO, 2012 a).

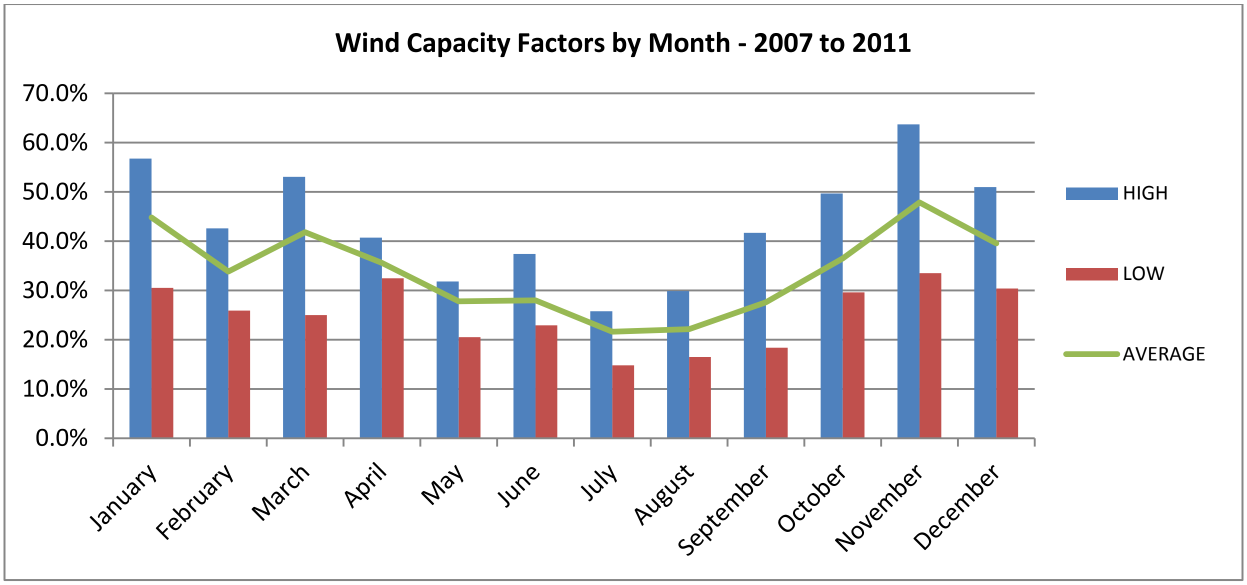


Figure 6: High, Low and Average Wind Capacity Factors by Month for 2007 to 2011

A review of capacity factors by month for the past 5 years indicates that aggregate wind generation has been historically more available in the late fall and winter and in some spring months, and on average drops to its minimum in the summer (Figure 6). The summer months consistently observe less wind for generation. This is also apparent when assessing wind speeds alone as can be seen in Appendix B. It demonstrates that for most wind resource areas, especially in the south, wind is highest during the day and daily peaks are typically highest during November and January. Wind speeds are lower in summer months, particularly July and August. Appendix C also demonstrates the effects of ambient air temperature on wind generation. It demonstrates that wind plant output (average generation as a percent of maximum capacity) peaks at temperatures between -5 C and 5 C. This appears consistent with the seasonal observations noted in Figure 6. Alberta's peak load does occur in winter and the highest capacity factors for wind are generally seen in these months which would suggest a greater value for their energy supplied[29]. However, these capacity factors overstate the capacity value of wind, "because wind is not firm supply and will be unavailable periodically despite relatively high average monthly output" (Pfeifenberger, J. & Spees, K. 2011, p 28)[30].

As more wind is added, the value it provides may change. Additional wind generation may displace more lower cost generation, and in doing so its volatility may create operational challenges for base load plants that are not capable of ramping up or down quickly to follow wind. It may be curtailed if base load plants

[29] Monthly capacity factors are identified in Appendix E for 2007 to 2011.

[30] The lower value of wind generation was also apparent in the summer when on July 9, 2012 four coal-fired and two gas fired generators tripped offline. Wind generation was 11 MWh when load reached an all-time record high of 9885 MWh at 2:00 PM, at the same time the unplanned outages occurred (AESO, 2012 e). An inadequate amount of supply was available resulting in rolling blackouts.

cannot reduce output below minimum operating levels. Reserve requirements will increase as more wind is added and greater drops in supply occur, especially if wind is highly correlated. This is discussed further in section 4.0.

3.2 Correlation of Wind Resources

Most current wind sites are located in the south west of the province and most new development will be located in this same area, with some in the south and centre east of the province. The location of wind generation in the market will affect the degree to which system reliability will be affected by wind generation. If all wind resources are highly correlated, high wind in one area should also be experienced in another and it is much more likely that wind generation will be either low everywhere or high everywhere. If it is not highly correlated, wind generation can be considered less unreliable and less volatile because if one area has low or no wind, it does not mean that all areas will have low or no wind. Negative correlations would imply that wind resources change in opposite directions (it is high is one area while low in another, or available in one area and not in another). This could be valuable to the system operator as a smoothing effect of aggregate wind energy supplied may be seen. The degree of correlation thus affects the reliability objective of the system operator. Further, when wind is all built in the same area, it is also a greater risk to reliability in the event it is isolated from the grid should a transmission constraint occur.

The analysis that follows is intended to assess the correlation of current wind generation facilities as well as determine how new wind generation currently being planned for development is correlated. As previously noted, there are 15 wind plants currently connected to the AIES and an additional twenty-eight plants are in the project queue. Hourly wind speed data at Alberta weather stations for the period January 1, 2008 and July 20, 2012 from the National Climate Data and Information Archive was used in conjunction with approximations for current plant geographic coordinates (longitude and latitude) to determine which weather stations were closest to which wind generation facilities (see Appendix I). Once each wind generating facility had a corresponding weather station, data from the weather station was used to correlate wind speed data between wind plants. The assumption is that those wind generating facilities which are highly correlated are expected to be generating at similar times and to similar relative levels of output into the system (turbine technical specification or down time is not considered)[31]. Those with low correlations can be expected to be available more independently of each other and have varying wind profiles, however a low correlation is less important if wind patterns are still similar by hour and season.

Correlations are considered perfect and positive if the correlation coefficient (the strength of the correlation) is equal to one. Correlation coefficients above 0.7 and less than 1 signify a strong positive correlation between the two variables (here weather stations, and by inference wind resources for wind generating stations). Correlation coefficients around 0.35 indicate a weak positive correlation, and 0 indicates no correlation (Bennett, J, Briggs, W, & Triola, M., 2009). Of the fifteen current wind plants, seven are close enough to each other such that the wind speed data are from the same weather station, and three more were closest to a separate individual weather station. Five were sufficiently isolated to be

[31] This method is a best approximation of wind at the site of the wind plants. Variations in actual wind speed between the weather station and a given wind plant, and even within a given wind plant are expected due to measured wind heights in relation to turbine heights, actual changes in wind speeds between turbines or between locations of data collection and generation, disturbances, natural or other obstacles, etc.

measured by separate individual weather stations. As such, without any further analysis, it is evident that much of the current wind generation is inherently correlated. Table 2 shows the correlation coefficients for each existing wind plant.

Table 2: Correlation Coefficients for Existing Wind Plants

	Ardenville Wind (ARD1)*	Blue Trail Wind (BTR1)*	Castle River #1 (CR1)*	Castle Rock Wind Farm (CRR1)*	Cowley Ridge (CRWD)*	Enmax Taber (TAB1)*	Ghost Pine (NEP1)*	Kettles Hill (KHW1)*	McBride Lake Windfarm (AKE1)*	Soderglen Wind (GWW1)*	Summerview 1 (IEW1)*	Summerview 2 (IEW2)*	Suncor Chin Chute (SCR3)*	Suncor Magrath (SCR2)*
Blue Trail Wind (BTR1)*	1	1												
Castle River #1 (CR1)*	0.76	0.76	1											
Castle Rock Wind Farm (CRR1)*	0.76	0.76	1	1										
Cowley Ridge (CRWD)*	0.76	0.76	1	1	1									
Enmax Taber (TAB1)*	0.43	0.43	0.36	0.36	0.36	1								
Ghost Pine (NEP1)*	0.19	0.19	0.13	0.13	0.13	0.32	1							
Kettles Hill (KHW1)*	1	1	0.76	0.76	0.76	0.43	0.19	1						
McBride Lake Windfarm (AKE1)*	1	1	0.76	0.76	0.76	0.43	0.19	1	1					
Soderglen Wind (GWW1)*	1	1	0.76	0.76	0.76	0.43	0.19	1	1	1				
Summerview 1 (IEW1)*	1	1	0.76	0.76	0.76	0.43	0.19	1	1	1	1			
Summerview 2 (IEW2)*	1	1	0.76	0.76	0.76	0.43	0.19	1	1	1	1	1		
Suncor Chin Chute (SCR3)*	0.73	0.73	0.62	0.62	0.62	0.52	0.29	0.73	0.73	0.73	0.73	0.73	1	
Suncor Magrath (SCR2)*	0.64	0.64	0.55	0.55	0.55	0.54	0.32	0.64	0.64	0.64	0.64	0.64	0.81	1
Suncor Wintering Hills (SCR4)*	0.15	0.15	0.09	0.09	0.09	0.37	0.50	0.15	0.15	0.15	0.15	0.15	0.23	0.28

Based on the weather data analyzed, it appears that the majority of current wind generation (51%) is strongly correlated. Of the 105 resulting correlation coefficients, 24 are perfectly correlated (1.0), 29 are strongly correlated (0.7-0.99), 27 are somewhat correlated (0.35-0.69), and the remaining 25 are weakly correlated (less than 0.35). No correlations are negatively correlated. Two current wind plants stand out as weakly correlated with other existing wind generators. These are Ghost Pine and Wintering Hills, both installed in 2011, and located in the Hanna and Sheerness planning areas, noticeably segregated from most existing generation. A comparison of wind generation (normalized for plant size) between these two plants and those plants more correlated in the south, shows that for the period January 1, 2012 to June 15, 2012, wind resources in the Hanna/Sheerness area were reflective of the lower capture prices (revenue per

MWh)[32]. The capture prices for Ghost Pine and Wintering Hills for this period were also lower than the average capture price for wind in the market. This does not account for any irregularities in generation, transmission, start up constraints, or technology that would affect the capture price. Although only a six month period was analysed due to the installation dates of these two plants, this might suggest that wind in this area is less valuable than wind in the south, however as noted in Figure 7, wind resources in these areas appear higher in the summer, for which data was not analyzed. This should be assessed further outside this paper.

Table 3 summarizes how correlated current and planned (i.e. in queue) wind farms are or would be correlated (see Appendix K for correlation information between plants). Although it is unlikely, if all queued wind plants are installed and connected to the AIES, wind will be less correlated than it is currently. This means that additional wind could reduce volatility and reliability issues related to highly correlated wind. However, this is not sufficient to eliminate (or to infer reduction of) reliability issues related to wind variability itself. It could also suggest that wind that is isolated from transmission constraints and which has a flatter wind profile could be more valuable than high wind areas alone.

Table 3: Correlation Coefficient Range Summary for Existing and Planned Wind Plants

	INSTALLED WIND	ALL WIND (INSTALLED AND IN QUEUE)
CORRELATION	105 Correlations	903 Correlations
1	23%	7%
0.7 - 0.99	28%	9%
0.35 - 0.69	26%	48%
0 - 0.34	24%	36%

As wind capacity grows, a positive smoothing effect of aggregated output could be experienced if sufficiently uncorrelated. However if wind capacity grows in the same resource-heavy location, sudden drops in supply can get bigger in size and increase system risk. Smoothing, whereby fluctuations can cancel each other out and reduce volatility in aggregate, will not be seen regardless of aggregated capacity if all wind is located in the same area. Alberta may be too small to see a noticeable smoothing effect however if wind capacity expands as per the current project queue, the risk of the increase in the magnitude of volatility may be less likely due to the reduction in correlation of wind resources. A reduction in the correlation of wind as more wind capacity is installed can help with meeting the system operator's reliability objective (relative to more highly correlated wind). Less correlated wind is more valuable to the system operator. However this must be balanced with the other objectives (such as efficiency discussed elsewhere in this paper). If the reduction in correlation can only be achieved by additional wind in the system, the additional costs of this added wind as discussed elsewhere must not exceed the benefit of the lesser correlated wind generation.

Figures 7 and 8 show average wind speed and average normalized generation by weather station/plant for each month and hour, where hours identified are the hours in each month, regardless of day. For example,

[32] Capture prices were calculated as follows: (Sum of pool price x generation per hour for the period)/(sum of hourly generation for the period). This was done for each wind plant. See Appendix J for details.

there are 31 instances per year of the hour 1:00 AM in January. Several observations can be made to generate some key points. First, wind profiles for most wind plants have similar wind profiles. That is, wind is experienced at highest levels during the day time (on-peak hours) and during the fall and spring month, with a low in the summer months. All wind, even less correlated wind, generally shows a consistent daily profile, with wind generally peaking in the afternoon. Some peaks are relatively higher, particularly those in the south, increasing volatility and reliability issues, where others are relatively lower or less volatile, such as those for Ghost Pine and Wintering Hills. In general, it appears that wind in the south is more volatile than wind in the Hanna and Sheerness areas, potentially increasing reliability issues as more wind is added in that area[33]. More wind added to the Hanna and Sheerness areas would still appear to cause reliability issues relating to the overall similarities in wind profiles by all plants, however all wind profiles appear to move with load whereby it is greater during on-peak hours. Seasonal winds appear less consistent between wind sites, however again, Wintering Hills and Ghost Pine show more consistency throughout the year. For example, winds near Wintering Hills (Sheerness area) appear to peak in summer months when winds in most other areas are lowest. Ghost Pine and Wintering Hills do not appear to peak or dip as high or low throughout the day or by season, and are generally more consistent relative to other wind profiles. Wintering Hills appears to experience lower relative wind speeds than other generators, however this does not appear to reflect relative generation as compared to other generators. Thus, the correlation of wind is somewhat indicative of reliability, however wind profiles that are similar in season or hour but are not highly correlated also affect reliability. Technology type, including its effect on capacity factor, is not considered in this analysis.

[33] Efficiency and fairness issues also arise and will be discussed in the Operating Reserves section.

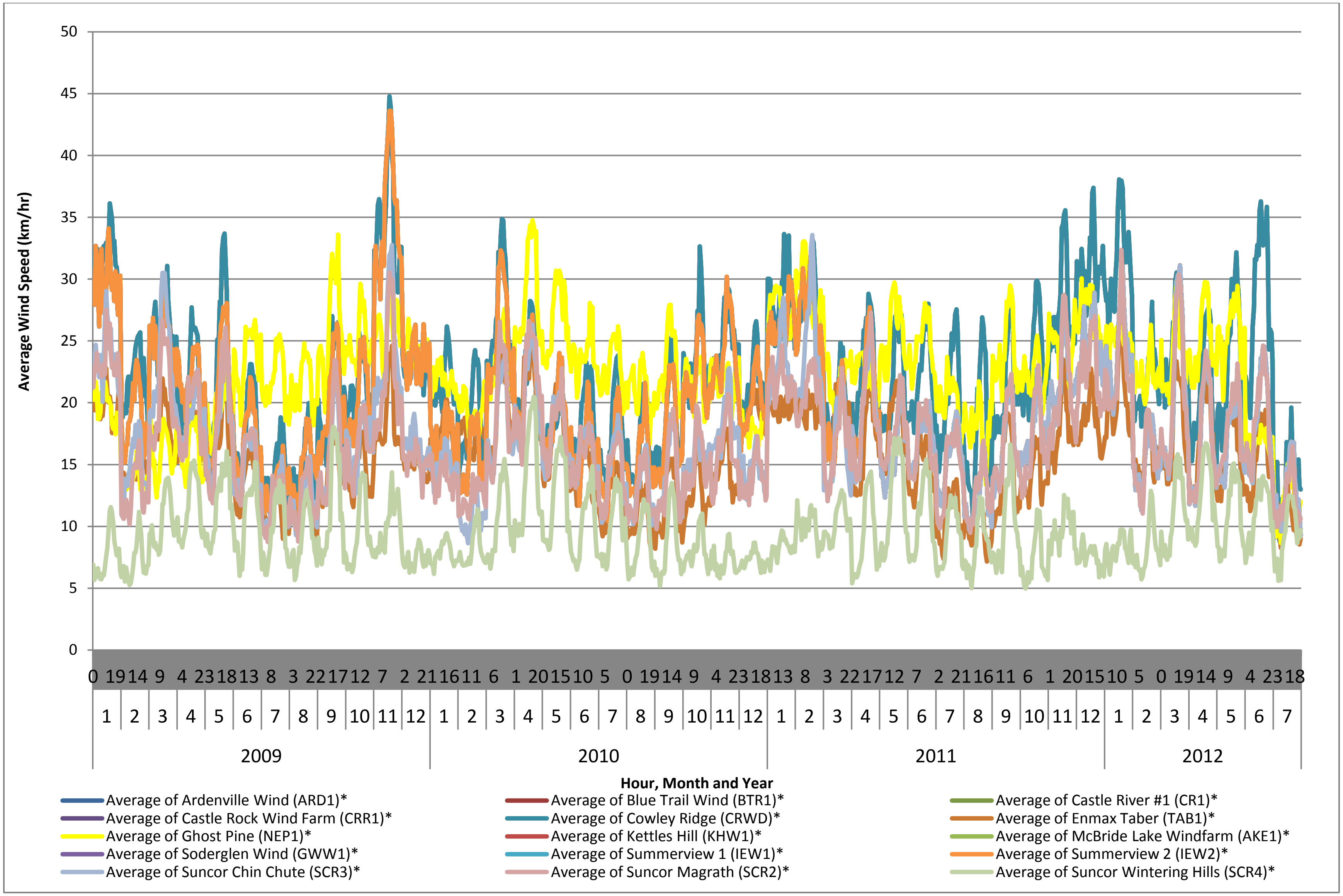


Figure 7: Average wind speed by month and year

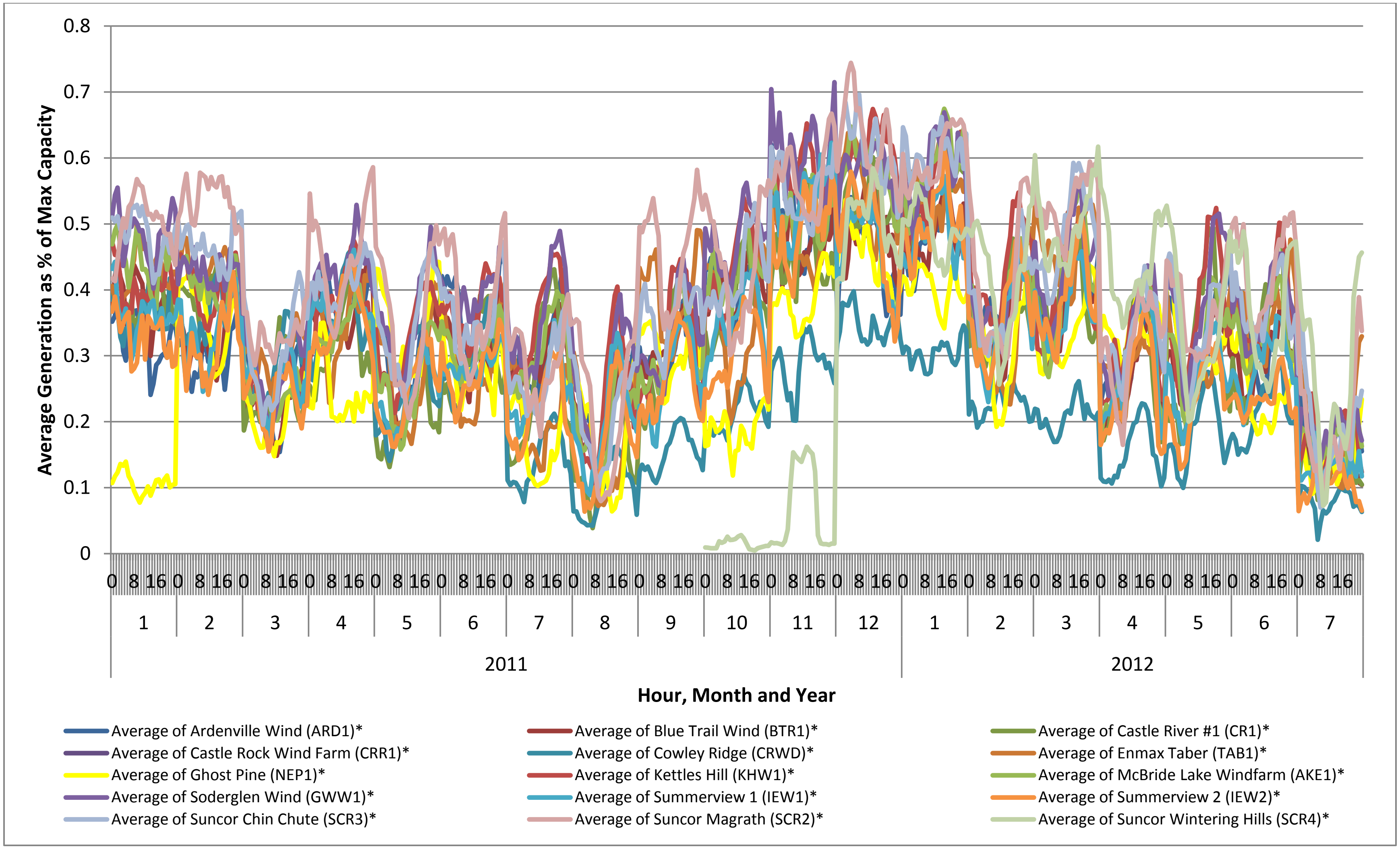


Figure 8: Average Generation as a percent of maximum/installed capacity for each wind plant by hour, month and year

3.3 Wind as Negative Load

Due to the volatility of wind and the inability of wind generators to provide firm power, wind generation can be treated as negative load. The effects of wind on the generation mix can be demonstrated this way using the load duration curve from Figure 2.1. If negative load (i.e. wind generation) is subtracted from actual load, the resulting net load can be treated in a conventional manner for planning purposes and drawn as a new net load duration curve[34]. Net load is actual load minus wind generation per hour and represents load without the volatility of wind. Figure 9 shows 2011 load and net load for Alberta[35]. It demonstrates the effects of the addition of wind on the economically optimal generation mix (i.e. allocation of conventional generation capacity (Davitian, 1978)). The shift down in the load duration curve represents the reduced load required to be met with conventional generation capacity and changes the optimal allocation of conventional generation. If the effect of wind is to decrease required base load and increase peaking capacity, this can result in investment savings in conventional plants due to peaking plants having a lower cost on a unit capacity basis than base load plants (Davitian, 1978). This savings however must be considered with the additional costs imposed by this wind. This will be assessed in section 4.

Using the current optimal mix of generation at today's costs (from Figure 2.2), Figure 9 shows that wind in the system requires the use of base load capacity when it is no longer the cheapest or most efficient technology (in the short run). Recall that the costs of energy supplied by each technology vary depending on the amount of time per year the plant operates. The optimal amount of peaking and base load capacity without wind are represented by D and E, respectively. These are separated by the optimal mix with no wind identified at A, where CCGT would be the least cost technology to meet base load in 76% of hours and SCGT would be the least cost to meet load in the remaining 24% of hours. This was demonstrated in Figure 2.2. In Figure 9, these would represent 12% and 88% of installed peaking and base load capacity, respectively. This is determined by finding the amount of load supplied in 76% of hours (of the year) and taking that amount of load as a percentage of total load for the year (on the vertical axis). Thus, the optimal mix based on $2011 and load data would be to use CCGT to supply base load up to about 8959 MW, (88% of total load) and use peaking capacity to serve load above this level[36]. As load duration is broken out into 8760 hours for the year, multiple load levels were observed at the point where 76% of load was supplied. As such, 8959 is the average load for the 88 hours in 2011 representing the level of load that was supplied 76% of the year (identified at the 24% point on the horizontal axis).

With wind, following the same analysis, the amount of peaking and base load capacity should be F and G, (separated by the new optimal mix identified at C), reducing the amount of base load and increasing the amount of peaking capacity by approximately 292 MW[37]. The 292 MW was determined by taking the difference between the average load for the hours at 24% on the 2011 Load curve (noted above to be 8959 MW) and the average load for the hours at 24% on the 2011 Net Load curve. Thus, the optimal mix based on $2011 and load data would be to use CCGT to supply base load up to about 8666 MW, and use

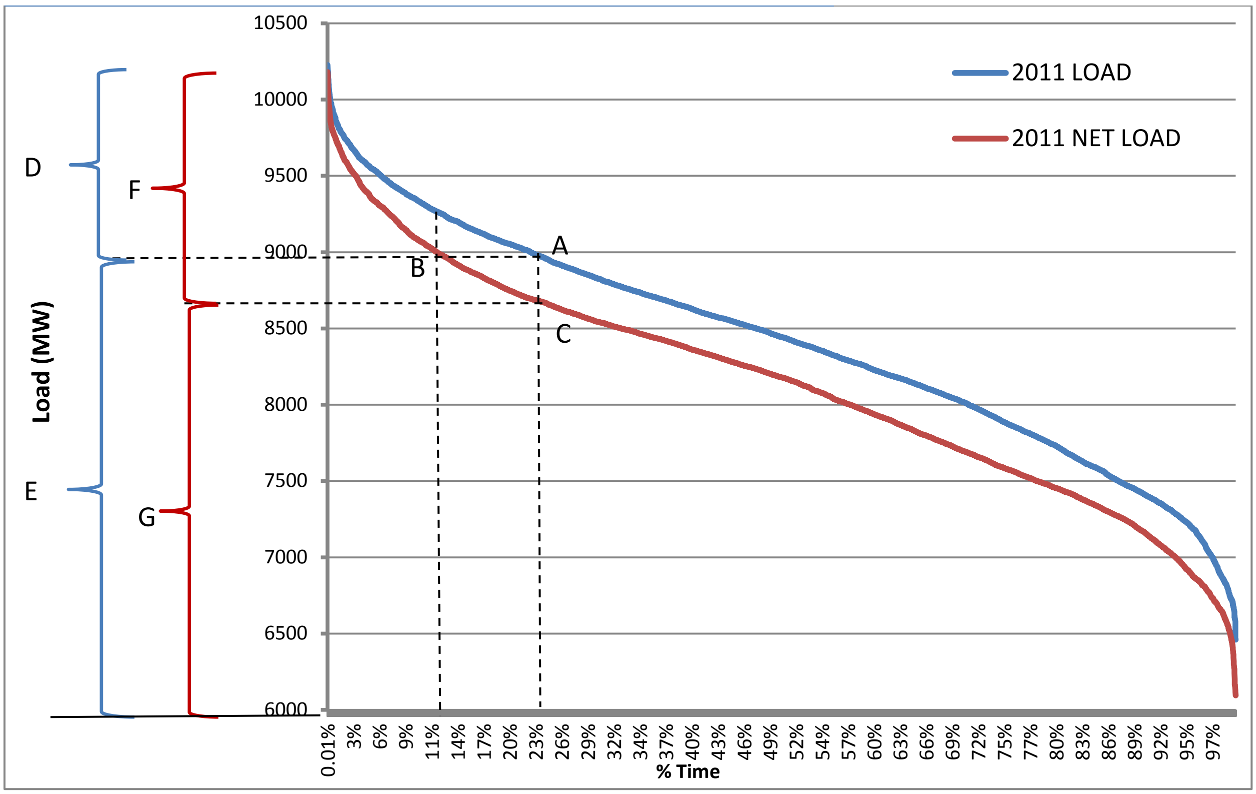
[34] This model is based on discussion with ATCO Power subject matter experts and reference to Stoft, S. (2002) and Davitian (1978).

[35] 2011 is used as a sample year only. The annual capacity factor in 2011 was 33%.

[36] These numbers reflect 2011 load data only and are used for the purposes of illustration.

[37] This number is for illustrative purposes only. It is based on data used for 2011 load and 2011 wind generation only.

peaking capacity to serve load above this level. A shift in the optimal amount of peaking and baseload capacity would occur, reducing the amount of baseload capacity from 88% to 85%, and increasing the amount of peaking capacity from 12% to 15%. This change in capacity from base load to peaking represents the change in the optimal generation mix when wind capacity is added to the system. This change in capacity however, cannot be attained in the short-run. The amount of peaking and base load capacity will only reach the new efficient amounts (i.e. with wind) after peaking capacity is installed and/or current base load capacity retires[38]. To reach the new optimal point with wind in the long-run, at C, the system capacity must pass through B in the short-run. Too much base load, and not enough peaking capacity are being used to supply energy reducing efficiency. This suggests that with wind generation, too much base load exists or would exist, relative to peakers[39].



Peak Load 2011 MW (0.01%)	**10226**	
Optimal Peaking Capacity (MW)	**D**	**1267 (12% of Peak Load)**
Optimal Base Load Capacity (MW)	**E**	**8959 (88% of Peak Load)**
Peaking Capacity Required with Wind (MW)	**F**	**1560 (15% of Peak Load)**
Base Load Capacity Required with Wind (MW)	**G**	**8666 (85% of Peak Load)**

Figure 9: Load Duration Curve for 2011 Load and Net Load

[38] This assumes wind is relatively newer to the generation mix and conventional generation already exists in the market.

[39] Recall that for the purposes of analysis, under the scenario described, and due to the marginal differences in costs of investment, CCGT is capable of serving both base and mid merit load and as such is combined and referred only to as base load.

Currently most base load is served by coal fired generation which has been demonstrated to be too expensive for new investment relative to alternative technologies. Considering that the present generation mix was not designed for the intermittency and variability of wind generation, there is too much coal fired capacity in the current generation mix which is not capable of meeting fluctuations in wind generation and not enough peaking capacity. If more wind is added, a greater negative load would add more volatility further suggesting that more fast-ramping capacity is required and that more peaking capacity should be installed. Overtime, the cost of maintaining coal will increase with additional wind and may affect both investment and retirement decisions. As more coal fired generation retires, the efficient amount of peaking and base load capacity could be achieved, once again using peaking capacity at the optimal level (although this assumes costs do not change and no new wind is added).

4.0 SOCIAL COST ANALYSIS OF WIND GENERATION

4.1 System Operator Objectives and Constraints

The objective of the system operator (the AESO) is to maintain the near-term reliability of the electricity grid while meeting the principles of a fair, efficient and openly competitive system. This can be interpreted as minimizing the sum of generation, transmission and ancillary service costs (EUA, 2003)[40]. These costs are all paid by or ultimately passed on to consumers. The AESO is unable to directly ensure adequate generation investment, however it does manage or have influence on transmission planning and ancillary services. The major constraints facing the ability to meet these objectives include:

- inadequate investment in generating capacity,
- growth in unreliable generating capacity,
- market power,
- unplanned failures of system components,
- unexpected changes in demand,
- government policy or regulation affecting investment decisions and retirement decisions of existing capacity,
- economic climate,
- transmission development costs (to remote locations of new generation) and congestion management,
- insufficient reserves, and
- the lack of information or control on where and in what types of generation facilities owners may develop or invest.

To meet forecasted demand, investment in new generation will occur and as noted, wind generation is anticipated to reach 15% of installed capacity by 2032, approximately 3000 MW. Wind generation will have the effect on system operating costs of a less efficient generation mix, and additional transmission capacity and ancillary service requirements that would not otherwise be required. It is expected that as

[40] Alberta Electric Utilities Act S.16"The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity". Although not assessed in this analysis, the objectives of the system operator as stated in the Electric Utilities Act may conflict with each other and their attainment may require a trade-off.

more wind is added, generation capacity will have constant returns to scale, (although additional generation will be required to back up wind capacity), transmission capacity will have increasing returns to scale because lines can be shared between generators, and ancillary services will have decreasing returns to scale because the system will become more volatile. The location of wind generation near valuable wind resources will require additional transmission capacity, and the timing and intermittency of wind generation will require additional generating capacity and fast ramping back up generation and operating reserves sufficient to meet sudden drops in wind power. The ability to ramp down quickly will also be required of other generators when sudden increases in wind power quickly come on to the system. The current system mix was not designed for the amount of wind capacity currently or expected to be installed. The value of wind energy to the system operator is also less than the value of other energy technologies because it is not guaranteed to be available when needed, is not dispatchable, is not available to be offered in other markets, tends to be further away from load, and be available when it is less needed (e.g. off-season) or unavailable when it is needed most (e.g. extreme heat or cold)[41]. The effects of wind on the generation mix (including the effects of correlation of wind resources), transmission requirements, and ancillary service needs will now be assessed.

4.2 Generation Mix

With respect to efficiency and minimizing costs of generation, the system operator is limited as investment will occur in response to market signals. Wind generation investment does however raise several concerns for the AESO's reliability and efficiency objectives. These include the additional costs of building capacity that is required only because of wind generation, the additional volatility that must be managed by the system as wind is added into the generation mix, and the imposition of costs on other generators in order to adequately meet demand and follow that volatility.

As noted in section 3.3, as more wind is added to the system, load will appear more volatile (as demonstrated when considering wind a negative load). Wind power can be replaced by existing generation at lower demand and so backup is less critical[42]. However at peak demand, where most available units are already running, energy must be supplied by additional capacity that would not be required if wind power was not part of the capacity mix. The level of generation required from non-wind technologies when wind is completely offline must still be sufficient to meet demand and maintain an adequate reserve margin. Assuming a 15% reserve margin and no other system constraints, the current 7% of wind capacity could be considered sufficiently backed up[43]. However, this then ultimately changes the effective reserve margin and would suggest investment in new generation should occur. It could also be argued that a 1:1 ratio of wind to backup generation must be ensured in order to maintain an adequate reserve margin. Table 4 shows the number of hours per year wind generation was 0 MW, less than 100 MW, and 500 MW or greater. The number of hours with 0 MW of wind generation is relatively low however it demonstrates that hours exist when no wind is available and may require 1:1 back up to meet the same level of demand.

[41] See appendices B and C

[42] This is assuming the next dispatch up the merit-curve is capable of ramping quickly enough to replace wind generation after operating reserves have been used.

[43] Note that effective reserve margins used in AESO forecasting do not include all installed wind and hydro capacity.

Table 4: Hours of Wind Generation for Selected Output Levels

	INSTALLED WIND CAPACITY AT DEC 31 (MW)	NO WIND HOURS (Less than 1 MWh) (HOURS IN 8760)	LESS THAN 100 MWh (HOURS IN 8760)	500 MWh OR GREATER (HOURS IN 8760)
2012 YTD *(01/01 to 07/15)*	939	17	1328	1269
2011	865	155	2928	1849
2010	777	528	4007	429
2009	563	389	4051	70

As an example, of the 528 hours with 0 MW of wind generation in 2010, 271 hours were on-peak and 257 were off-peak. If 271 hours with 777 MW of installed capacity not supplying energy during on-peak hours does not create supply shortages then a 1:1 back up ratio may not be required. The AESO de-rates wind to include only approximately 20% of installed capacity[44] in determining its effective reserve margin for forecasting purposes, possibly suggesting that 80% of wind should be backed up by other generation. If wind generation is eliminated from the generation mix effectively increasing load, and is replaced by gas-fired generation, the entire amount of installed wind capacity is not required to be replaced. A lesser amount of reliable generation is required to make up for the amount of variable wind generation. Ultimately, the adequate level of wind in the system without backup, where reliability can be ensured and additional capacity is not required, will be the level where the cost of additional backup equals the cost of any loss in reliability.

The following analysis will compare a "wind" and a "no wind" scenario. Gas-fired generation has been demonstrated to be the least cost technology and provide reliable and firm power. As such the assessment of the cost of wind generation will be compared to gas-fired generation in the no-wind scenario. The analysis is intended to demonstrate the difference in cost to meet the same energy requirements using either:

- WIND SCENARIO: wind capacity, as installed and forecast, or
- NO WIND (i.e. GAS) SCENARIO: existing gas-fired generation, plus new gas-fired capacity representing 20% of the installed wind capacity no longer in the system
    - The gas scenario is conducted twice, once for each of SCGT and CCGT

The principle to be demonstrated in the analysis is that the cost required for wind generation is an additional cost that is not required in a "no wind" scenario[45]. As the level of back-up required for wind is arguable, for this analysis the AESO de-rate assumption will be applied and it will be assumed that 80% of installed wind capacity should be backed up. It will be assumed that in a no wind scenario, 20% of wind capacity that would otherwise be in the system should be built by gas-fired technology, and that the remaining energy requirements will come from existing generation running more often.

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[44] The AESO also de-rates hydro by varying factors depending on the type (AESO, 2012 b).

[45] It is assumed that in the no-wind scenario, reliability, efficiency and cost minimization objectives are attained. Capacity required to meet load growth is not assessed directly. Only the difference in cost should that capacity be met with wind versus gas is assessed.

To assess the cost of wind imposed from not using lower cost, more reliable and firm generation, several factors must be included in the analysis. These include[46]:

A. The additional capital and fixed operating costs for wind capacity relative to gas-fired capacity (i.e. the cost of wind capacity relative to the cost of 20% of that capacity required by gas-fired capacity);
B. The fuel savings from wind generation which replaces gas-fired generation (i.e. the difference in the cost of energy supplied by wind versus gas-fired generation); and
C. The credit to wind generation for requiring a cheaper mix of technology in the market (i.e. more peaking and less base load capacity, as demonstrated in Figure 9).

The analysis is conducted for the period 2000 to 2032. The results of the calculation of the additional capital and fixed costs of wind, less the savings from variable costs saved by wind (items A and B) are demonstrated in Table 5. These results demonstrate the additional cost of wind imposed relative to using gas-fired generation to meet the energy requirements currently and projected to be provided by wind generation. The results of item C are discussed following Table 5.

With no wind generation in the system, and using the AESO's de-rate amount of 20% as what amount of additional capacity should be installed with current levels of wind removed, an additional 170 MW of capacity must be built by gas-fired generation and is thus added to the No Wind scenario for 2011. Capacity requirements to replace wind in future years are then calculated for 2017, 2022 and 2032 maintaining the 20% de-rate amount to demonstrate the continued effects of additional wind on system operating costs in the future[47]. Capital and fixed O&M costs are derived from these capacity requirements. Variable O&M costs are based on a calculation of the energy supplied by current and projected wind generation at a constant capacity factor of 35% to determine the fuel savings relative to gas-fired generation. This is the generation provided by wind that would need to be provided by gas-fired technology in the No Wind scenario. Both SCGT and CCGT costs are calculated relative to wind to demonstrate the difference between replacing wind generation with either type of gas-fired technology. All costs are discounted to 2011 using a discount rate of 10%[48].

Calculations in Table 5 are based on the following assumptions:

Capital Costs:

Overnight capital costs (2011$) are used to calculate the cumulative capital costs on the system from additional wind. These represent sunk costs for 2011 and expected sunk costs (as of today) for 2017, 2022 and 2032 should installation proceed as forecast. Capital costs are calculated by multiplying overnight capital costs ($/kW) by (1000kW/MW) by installed capacity (MW).

[46] This model is based on discussion with ATCO Power subject matter experts

[47] Scaling up the capacity required in the subsequent years is assumed to be linear for the purposes of demonstration. In reality, it is unlikely that this would be linear and that the amount of back-up would increase relative to the amount of additional wind generation installed.

[48] Costs were multiplied by the discount factor (1/(1+r)^(T-2011)), where r is the discount rate and T is the year.

- Costs between 2000 and 2011 are based on installed capacity per year from the AESO 2011 Annual Market Statistics Generation Additions information[49]. Capital costs were assessed for forecast capacity at intervals of 2011, 2017, 2022 and 2032 as per the AESO forecast provided at these intervals.
- The real average capital cost of all the existing 865 MW of wind capacity is assumed to be equal to today's overnight cost of $2300/kW (i.e. that this was the average cost of installation each year for the incremental MW of wind capacity built). $2300/kW is the constant real average capital cost for each year up to 2032 and any forecasts based on either increased or decreased capital costs are ignored. This is held for SCGT and CCGT at capital costs of $1,150/kW for SCGT and $1,435/kW for CCGT (for a 300 MW plant).
- Forecasted gas capacity is taken as 20% of the wind capacity as an estimate of the amount of gas-fired generation required to replace wind, thus required in a no-wind scenario[50].
- All costs are real (2011$) and are discounted to 2011 at a discount rate of 10%.

Fixed Costs:

Fixed O&M costs were calculated by multiplying installed capacity by the fixed O&M costs per year for each of wind and gas (after converting to MW). These represent annual costs that must be paid regardless of operation and which can only be avoided by leaving the market.

- Fixed operating and maintenance costs were assessed annually from 2000 to 2032. Costs between 2000 and 2011 are based on installed capacity per year from the AESO 2011 Annual Market Statistics Generation Additions information. Forecasted wind capacity for 2017, 2022 and 2032 was taken from the AESO 2012 Long Term Outlook. It was assumed that for the years between 2011, 2017, 2022 and 2032, forecasted generation was installed in an evenly distributed manner in each year leading up to the given year as interim years were not provided.
- The real average fixed O&M cost each year since 2000 is assumed to be equal to today's cost of $50/kW per year. $50/kW per year is the constant real average capital cost for each year up to 2032 and any forecasts based on either increased or decreased costs are ignored. This is held for SCGT and CCGT at capital costs of $14/kW per year for SCGT and $15.50/kW per year for CCGT (for a 300 MW plant).
- Forecasted gas capacity is taken as 20% of the wind capacity as an estimate of the amount of gas-fired generation required to replace wind, thus required in a no-wind scenario.
- All costs are real and are discounted to 2011 at a discount rate of 10%.
- All costs are annual (2011$/year).

Variable Costs:

To determine the energy supplied by wind generation, and thus the energy that would need to be replaced in the No Wind scenario, Variable O&M costs were calculated using a capacity factor of 35% and the installed wind capacity at the end of each year. For example, in 2011 865 MW x 8760 hours x 35% resulted in 2,652,090 MWh. This amount of generation per year was then calculated in relation to which technology would provide it to compare the cost of providing this energy with wind versus gas-fired

[49] The two plants installed prior to 2002 were added in separately. See Appendix M for details by year.
[50] This method was used after lengthy discussion about the validity of other methods.

generation. Energy supplied by wind is calculated as installed wind capacity (MW) per year multiplied by the number of hours per year (8760) and by the capacity factor for wind (35%).

- Variable operating and maintenance costs (including fuel) were assessed annually from 2000 to 2032. Costs between 2000 and 2011 are based on energy supplied from installed wind capacity per year at a capacity factor of 35% for wind. Forecasted wind capacity for 2017, 2022 and 2032 was taken from the AESO 2012 Long Term Outlook. It was assumed that for the years between 2011, 2017, 2022 and 2032, forecasted generation was installed in an evenly distributed manner in each year leading up to the given year as interim years were not provided.
- The real average variable O&M cost for wind generation each year since 2000 is assumed to be equal to today's cost of $2/MWh. $2/MWh is also assumed to be the constant real average capital cost for each year up to 2032 and any forecasts based on either increased or decreased costs are ignored. This is held for SCGT and CCGT at capital costs of $54.20/MWh for SCGT and $41.37/MWh for CCGT (for a 300 MW plant)[51].
- All costs are real and are discounted to 2011 at a discount rate of 10%.
- All costs are annual (2011$/year).

The costs for both fixed and variable O&M identified in Table 5 are the cumulative annual O&M costs up to the year identified, measured at the end of each year. Table 5 shows total cumulative costs of wind generation for 2011, 2017, 2022 and 2032. Costs relating to gas-fired generation in each category are subtracted from costs relating to wind generation for a resulting net cost of using wind generation instead of gas-fired generation.

Detailed results (per year) can be found in Appendix M. Total Cost is the sum of each of the capital, fixed O&M and variable O&M for each technology. The difference in Total Cost between wind and gas-fired generation is the additional cost paid for the generation required to back up wind or replace its energy supplied. The cost of additional capacity less fuel savings are demonstrated to be $1.1 billion to 1.3 billion (2011$) as of today, depending on which type of gas-fired generation replaces wind energy. The present value of these costs for the next five, ten and twenty years is identified in the Table 5. These are the extra costs due to wind to have built and operated current capacity up to 2011 levels, and to build and operate current and projected capacity for 2017, 2022 and 2032 respectively relative to building more reliable capacity at a lower cost. These costs represent the economic value that is lost due to the excess capacity installed less any savings from wind generation.

The different results from using SCGT versus CCGT to replace wind capacity and generation demonstrate that the additional costs imposed by wind are dependent on the capacity and energy it is displacing. Wind appears to cost less when it displaces SCGT than it does when displacing CCGT. This is mainly due to the higher variable O&M costs from SCGT that would not be required to be paid, and which outweigh its lower capital and fixed costs. These results are discussed in relation to the cost of carbon abatement in section 6.

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[51] Variable O&M includes Variable Fuel costs ($/GJ x Heat Rate). Details can be found in Table 1 or Appendix F. These include $0.90/MWh and $0.67/MWh for emissions and $5.00/GJ gas price.

Table 5: Cumulative Costs of Additional Wind relative to gas-fired capacity and generation (Present Value of real 2011$)

Net Cost is Cost for Wind less Cost for specified Gas technology. Total Cost is sum of each of capital, fixed O&M and variable O&M for the technology specified.

	2000-2011	2000-2017	2000-2022	2000-2032
CAPITAL COSTS				
WIND	$1,989,500,000	$4,188,803,326	$6,239,613,231	$7,351,656,751
GAS – SCGT	$198,950,000	$418,880,333	$623,961,323	$735,165,675
NET	**$1,790,550,000**	**$3,769,922,994**	**$5,615,651,908**	**$6,616,491,076**
FIXED O & M				
WIND	$306,475,424	$591,829,524	$824,182,032	$1,150,738,805
GAS – SCGT	$17,162,624	$33,142,453	$46,154,194	$64,441,373
NET	**$289,312,800**	**$558,687,071**	**$778,027,838**	**$1,086,297,432**
VARIABLE O & M				
WIND	$37,586,146	$72,581,973	$101,077,684	$141,126,607
GAS – SCGT	$1,018,584,556	$1,966,971,465	$2,739,205,246	$3,824,531,052
NET	**-$980,998,410**	**-$1,894,389,492**	**-$2,638,127,562**	**-$3,683,404,445**
TOTAL				
WIND	$2,333,561,570	$4,853,214,824	$7,164,872,947	$8,643,522,164
GAS – SCGT	$1,234,697,180	$2,418,994,251	$3,409,320,763	$4,624,138,100
NET	**$1,098,864,390**	**$2,434,220,573**	**$3,755,552,184**	**$4,019,384,063**

	2000-2011	2000-2017	2000-2022	2000-2032
CAPITAL COSTS				
WIND	$1,989,500,000	$4,188,803,326	$6,239,613,231	$7,351,656,751
GAS – CCGT	$248,255,000	$522,689,806	$778,595,216	$917,358,908
NET	**$1,741,245,000**	**$3,666,113,520**	**$5,461,018,015**	**$6,434,297,844**
FIXED O & M				
WIND	$306,475,424	$591,829,524	$824,182,032	$1,150,738,805
GAS – CCGT	$19,001,476	$36,693,431	$51,099,286	$71,345,806
NET	**$287,473,948**	**$555,136,094**	**$773,082,746**	**$1,079,392,999**
VARIABLE O & M				
WIND	$37,586,146	$72,581,973	$101,077,684	$141,126,607
GAS – CCGT	$777,469,430	$1,501,358,109	$2,090,791,901	$2,919,203,868
NET	**-$739,883,284**	**-$1,428,776,136**	**-$1,989,714,217**	**-$2,778,077,261**
TOTAL				
WIND	$2,333,561,570	$4,853,214,824	$7,164,872,947	$8,643,522,164
GAS – CCGT	$1,044,725,906	$2,060,741,346	$2,920,486,403	$3,907,908,581
NET	$1,288,835,664	$2,792,473,478	$4,244,386,544	$4,735,613,583

Wind generation can also be credited for requiring cheaper per MW installed capacity in the optimal system mix (item C above). The cost savings that can be credited to wind generation from the change in capacity mix can be demonstrated from the results of the negative load model in section 3.3. Using the data from 2011 analyzed in section 3.3, if a credit is applied to wind generators for requiring a cheaper mix of conventional generation relative to a no-wind scenario, it would be represented by the 292 MW that was demonstrated to be served by peaking and not base load capacity. Using the $2011 capital costs for each of SCGT and CCGT of $1,150 and $1,435/kW, the savings from building peaking capacity instead of base load capacity for 292 MW would be approximately $83 million. This was calculated by multiplying 292 MW by the respective capital costs for SCGT and CCGT (in $/MW) and taking the difference. SCGT is more expensive to operate and has a higher heat rate so would be less efficient in the conversion of fuel to energy, however it also generally operates at a lower capacity factor. If 292 MW of SCGT was installed in place of CCGT, and operated at the capacity factors used for these technologies throughout this analysis, (30% and 67.5% respectively), SCGT would cost approximately $30 million less to operate per year. (This is based on the same cost inputs used for the analysis in Table 5 and re-calculating the fixed and variable O&M costs for 292 MW. Variable O&M use the capacity factors identified in the previous sentence). As more wind is added, the credit to wind will grow as more peaking capacity is required instead of base load capacity. If scaled up as a percent of total installed capacity, the present value of this savings would be $18 million for 2032 (or $134 million in real dollars)[52].

Wind generation ultimately acts to reduce load and make it more volatile, thereby reducing the amount of base load capacity that should be in the market and increasing the amount of peaking or fast-ramping capacity. With more and more wind generation capacity, fluctuations in load effectively begin to resemble much larger fluctuations than would be anticipated from expected daily load profiles. This will require much larger and faster availability from other generators. If all installed wind capacity was generating today, a sudden drop in all wind would require 939 MW of wind power to be replaced immediately (assuming no change in demand). Some of this could be replaced with the current level of operating reserves, and the rest by dispatching up the merit-curve. A sudden drop in all wind at an installed capacity such as 2000 MW would require that a much larger portion of the merit-curve be dispatched immediately to maintain reliability as operating reserves would be insufficient. It also requires that more fast ramping generation be available in a market where a large amount of base load is currently relatively cheap to sustain, at least in the short term.

The rate at which large fluctuations in wind occur and require dispatches up and down the merit-curve to compensate for wind generation continuously coming on and off line will depend on the amount of wind capacity and the correlation of wind resources. These fluctuations are not however conducive to most current base load generation. Fluctuating output reduces the operating efficiencies of these plants, which must incur additional costs from continual cycling and the greater likelihood of operation outside normal or optimal limits. Additional costs on conventional generators, particularly large base load plants will also emerge as additional wind is added due to the way wind generation currently enters the energy market as 'must-run'. As the amount of energy supplied at $0/MWh from wind increases, the amount of total energy offered at $0/MWh will increase. Minimum operating levels for a coal plant are approximately 40% of

[52] 2% of forecast installed capacity of 23,577 from Appendix G scaled from 292 MW being 2% of installed capacity in 2011

maximum capacity[53]. As noted previously, to ensure operation at this level these plants will be willing to offer in this amount of their installed capacity at $0/MWh and run at pool prices below variable cost in order to save the costs relating to shutting down. As more wind is added, these larger base load plants may be required to ramp down to levels lower than minimum operating limits and subsequently shut down, incurring large costs. This also leaves them unable to come back on when wind slows at a faster rate than these plants can ramp or start up. Negative pricing has been incorporated into other competitive energy markets allowing generators to offer to pay the system operator to allow them to maintain required production levels, a cost lower than the costs of shutting down. However if wind subsidies from third parties allow wind generators to offer lower negative prices than other generators, this will not solve the problem of the effects of wind on the cycling and shutdown costs of other generators because wind may be able to offer a lower negative price than other generators which do not have these subsidies to help offset operating costs. This would occur as long as any maintenance penalties of shutdown, especially for large coal-fired units, did not exceed the effect of subsidies. This may affect retirement decisions for coal-fired generators and worsen the transitional effects of early retirements. If CCGT is to replace coal as expected, it is likely that better ramping capability will be seen by base load.

To summarize the effects of wind on the current generation mix, it creates a scenario where too much base load exists in the short run and an uncertain mix will exist in the long-run depending on changes in costs of various technologies and responses of base load capacity to impacts of wind. It also results in additional system costs not required to maintain reliability, and subsidized wind generation by non-wind generators which are required to respond to the variability of wind. The fuel savings and credit for lower installed capacity costs from requiring more peaking than base load capacity exist but are not significant enough to offset any capital or fixed costs imposed by wind capacity, resulting in large costs imposed on society for the benefits of renewable energy. The effects of wind on revenue for other generators are discussed in section 5.

4.3 Transmission

The inclusion of transmission costs in this paper is brief and intended to demonstrate the relative transmission costs of current and future wind generation compared to gas fired generation. Only the cost of incremental bulk transmission costs will be assessed. Local connection costs paid by generators are assumed to be equivalent in aggregate and too local to generalize. Bulk transmission costs are largely based on capital costs of transmission line and substation development or upgrade[54]. These costs are paid directly by consumers and affect the objectives of the AESO to ensure an efficient and reliable system. Line losses can also generate costs to suppliers however they will not be considered for this assessment. It should be noted however, that line losses should be greater for those generators further from load and thus would generally be higher for wind generators than gas-fired generators. Constrained down generation costs are also reported to be higher for wind[55]. "Constrained down generation occurs when the amount of

[53] This is based on discussion with ATCO Power subject matter experts.
[54] Direct costs of transmission include telecommunication, salvage, owner and distributed costs (based on the AESO Final Cost Reporting Template available online).
[55] Wind generation in the south is one of the main sources of constrained generation in the province (AESO 2012 c, Appendix K). In 2010, the number of hours with constrained down generation from wind entered by the system controller was at least 1,078 (of a total of 3,295 hours) and the average estimated cost on the system of constraints related to wind was $76.4 million (AESO 2012 c, Appendix K). In 2011, at least 671 of 1,646 hours had

supply a generator can transfer to load is limited by insufficient transmission capacity" (AESO, 2012 k). It should also be noted that transmission development costs and constrained down generation or congestion costs will require a trade-off as both reflect separate system needs. Additional transmission capacity can alleviate constrained down generation and should be added once costs related to reliability inadequate transmission capacity exceed the costs of reliability from constrained down generation. As more generating capacity connects to existing transmission, congestion costs or constrained down generation may begin to increase until new development is again required.

A large component of transmission costs is based on location of generation. Wind generation differs from gas-fired generation in its inflexibility in 'fuel' and thus development location. As noted in Figure 5, valuable wind resource areas are generally located further from load. Gas-fired generation, (with the exception of cogeneration) is more flexible than wind and other generation technologies in where it can be located and is not as limited by fuel location due to the well developed existing pipeline infrastructure in Alberta[56]. It is assumed that gas-fired generators would act rationally and would not locate in remote areas if the cost to locate closer to load and fuel is lower. The capital costs required for transmission of wind generation can therefore generally be expected to be higher relative to gas-fired generation due to the remote locations of wind resources, and the flexibility of location with gas fired power plants to locate near load or existing infrastructure. Growth in bulk transmission related to load growth alone is not considered as part of this analysis. This assessment is intended to demonstrate the difference in system costs should additional wind be used as forecast to meet increased load, or should gas-fired generation be installed instead creating a 'no wind' scenario, and demonstrating the relative costs of bulk transmission for wind capacity.

In order to accommodate the majority of current wind capacity, the Southern Alberta Transmission Development Project (Project 416) was applied for in 2004 and completed in 2011, with a final cost of \$238 million (2011\$) (Government of Alberta, 2011). In addition to this project, the Southern Alberta Transmission Reinforcement (SATR) Project (Project 787) was applied for in 2008 in order to ensure adequate system access for the interconnection of additional wind generation (Government of Alberta, 2011). This project was applied for to enable transmission capacity for 1700 MW of wind generation in the south by approximately 2017, with second and third phases of the project to be developed to meet the higher forecast of 2700 MW in the south of the province. The first phase of the SATR was projected to cost \$750 million in 2008 (\$1310.5 million in 2011\$) and the total project cost is currently expected to reach \$2,287 billion (2011\$). Because Projects 416 and 787 were approved for transmission of incremental wind generation, they are considered a good proxy for the incremental costs of transmission to serve wind generation. Transmission for the 865 MW of wind in 2011 is approximated by the cost of Project 416 and the completed portion of the first phase of the SATR (Project 787) as of 2011. Transmission costs for 2017 will include the remainder of the first phase costs for the SATR. The second and third phases of the project are approximated to meet the remainder of the forecast, a total of 2700 MW. Transmission for the 173 MW of generation that would be required with no wind (from the assessment earlier in the section) is considered to require only local connection and no additional bulk transmission. Since wind generators also face local connection costs, these costs are neglected for the

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constrained down generation from wind (AESO, 2012 f). The accuracy of these costs is debatable and as such they have not been included in the present analysis.

[56] Pipeline access, availability of water, transmission access and a receptive community are noted by the AESO 2012 Long Term Outlook as important factors in siting gas-fired generation.

purposes of this comparison and can be considered, in aggregate to be equivalent. Although relative local interconnection may be too local to generalize, it could reasonably be presumed that in the majority of cases these costs would be lower for the connection of one gas-fired plant relative to multiple wind turbines over a larger land area. This assumption continues for each segment of additional gas-fired generation identified in subsequent years.

The resulting relative costs of bulk transmission for wind versus gas-fired generation are identified in Table 6. The 2011 value for the cost of bulk transmission with wind is derived from adding the portion of the SATR completed as per December 2011 identified in the TFCMC Report, 2011 to the cost of Southern Alberta Transmission Development Project ($238 million plus approximately $42 million). The remaining costs identified for 2017 and 2022 are the present value of the costs identified to complete transmission for 1700 and 2700 MW, respectively, using a discount rate of 10%. The cost of additional transmission capacity is demonstrated to be $280 million (2011$) as of today. The present value of these costs for the next five and ten years is identified in the Table 5. These results indicate the economic value that is lost due to excess transmission capacity in relation to what would be required in a no-wind scenario. The values represent sunk costs for 2011 and expected sunk costs (as of today) for 2017 and 2022 should wind capacity proceed as forecast. These results demonstrate the additional transmission capacity costs paid to connect wind to the AIES. They are the extra costs due to wind in relation to the no-wind scenario and represent the economic value to society that is lost due to the excess transmission capacity installed.

Table 6: Cumulative Bulk Transmission Costs for Wind relative to Gas-Fired Generation (Present Value of real 2011$)

Installed Wind Capacity (MW)	Cumulative Bulk Transmission Cost ($ millions)			
500	$238			
1700	$1,017			
2700	$2,287			
	2011	2017	2022	2032
Installed Wind Capacity (cumulative)	865	1694	2544	3578
Gas-Fired Capacity Required with No Wind (cumulative)	173	339	509	716
Cost of Bulk Transmission with Wind – Present Value ($ millions)	**~$280**	**~$574**	**~$802**	
Cost of Bulk Transmission for Gas-Fired Generation with No Wind (cumulative)	$ -	$ -	$ -	

As noted earlier, transmission costs are expected to have increasing returns to scale, such that as more transmission capacity is built, additional generation can connect to existing infrastructure and new transmission development costs should increase at a slower rate than increases in installed capacity. The bulk transmission costs for wind assessed above reflect a linear relationship between additional wind capacity and bulk transmission costs, however this assessment was overly simplified for the purposes of demonstration.

4.4 Operating Reserves

As noted earlier, the AESO is responsible for balancing supply and demand in real time. With wind generation in the system mix, supply can also fluctuate like demand and effectively increase load volatility. Currently, regulating reserves are in place to balance small fluctuations in supply and demand and provide a ramping service where the energy market cannot keep pace with changes in load (AESO, 2010 b, p. 15). They take into consideration system ramps, load fluctuations, and the ramping capability of the EMMO, however they do not currently consider wind power variability (AESO, 2012 a) although they are used to balance the system for this purpose (AESO, 2010 b). The system is also currently equipped with contingency reserves to manage unexpected losses of generation, but these must also be available for non-wind related generation losses. North West Power Pool (NWPP) policy does not currently allow the current mandatory level of contingency reserves to be used to replace unexpected loss of wind generation due to a reduction in wind speed[57]. Neither type of reserve can address wind ramp-up events which are a new variable in the system from wind (AESO, 2010 b). Operational challenges are created as more wind is added to the system requiring the availability of reserves or fast ramping units to be available when the wind stops blowing, and the ability to handle excess generation when the wind ramps up very quickly. As a result, the reliability objective of the AESO is greatly affected by the adequacy and availability of operating reserves. Direct costs of operating reserves are paid by load through the transmission tariff. The costs of operating reserves for the past five years are noted in Table 7. The price paid to providers of operating reserves is indexed to the pool price and therefore fluctuates with the market. As noted, these costs have not specifically incorporated additional reserves for wind variability. With respect to its cost minimization and efficiency objectives, the AESO would be expected to incur higher costs as more wind capacity is added, and these costs can be expected to rise at a faster rate than the rate of growth of installed wind capacity. With increased volatility as wind is added to the generation mix, "AESO studies have determined that the reliable operation of the system requires new tools and practices to be in place prior to connecting 'this level' (approximately 1100 MW) of wind capacity" (AESO, 2010 b). This section will assess the costs of current and additional wind capacity on the requirements to procure operating reserves relative to a no-wind scenario. Cost information will be limited in that no reserve products are specifically procured to date for wind variability and attributing specific fluctuations in costs of operating reserves to wind is difficult.

Table 7: Total Cost of Operating Reserves (Source: AESO 2011 Market Statistics (AESO, 2012 a))

	Total OR Cost ($ millions)	Average hourly pool price ($/MWh)
2007	$185	$66.95
2008	$270	$89.95
2009	$104	$47.81
2010	$137	$50.88
2011	$328	$76.22

[57] This is noted by the Reserve Sharing Operating Procedure which indicates that contingency reserve cannot be used for general system balancing needs absent a contingency event (AESO Paper 2, 2010).

As the current generation mix is not equipped with an optimal amount of peaking or otherwise flexible supply for the level of wind generation installed, and has too much base load (mainly inflexible coal) capacity, it is also not prepared for the additional wind in the interconnection queue. This shortage in flexible supply can raise the price of operating reserves by making them more valuable in following fluctuations in supply and demand. Until additional flexible capacity is installed, as should occur with respect to the costs of investment in gas-fired generation today, system objectives and costs will be affected. Solutions to manage additional wind in the system will affect reliability, fairness, efficiency and cost objectives differently. In general, major concerns relating to operating reserves originate from wind generation not being required to submit offers into the market for their energy, and not being held accountable for their production when the variability of that energy imposes costs on both the system and other generators (AESO, 2010 b, p. 21).

In 2010, the AESO developed a short-term wind integration plan for the accommodation of 1100 to 1500 MW of wind on the system. They recommended that when ramp requirements of the energy market merit order (EMMO) capability are exceeded, incremental standby contingency reserves be procured (above the minimum specified by the NWPP) and dispatched to replace lost wind power when sudden drops in wind occur, and Wind Power Management (WPM) be used to control wind ramp up events. WPM means that wind energy produced that cannot be accommodated (generally due to rapid ramp up) is temporarily limited (or curtailed) to what the system can handle (AESO, 2010 c)[58]. These recommendations are based on the premise that wind ramping up is a controllable event, and its costs should not be paid for by load but by wind generators (just like all other generation types must pay for controllable events) and loss of wind energy is uncontrollable and should be managed by services paid by load (AESO, 2010 c p. 8-9). It was assessed that the use of standby reserves is the most efficient tool "currently available" to manage wind ramp down events on an as needed basis and that WPM is the most efficient means currently available to manage wind ramp up events (AESO, 2010 c). These solutions however will not be sufficient as more wind capacity is added to the generation mix. They also raised concerns by stakeholders that the AESO is "creating solutions to a problem created by the fact that wind does not offer into the market and is not held accountable for its production relative to that offer" and that the use of contingency reserves to manage wind ramp down events results in incremental costs being allocated to load (AESO, 2010 b).

The system is currently operating at a wind capacity level approaching the limits of the short term plan. A 'Phase 2' wind integration plan was also developed to meet the challenges provided by additional wind on the system in the long term and determine the most efficient market solution. This plan would be required when wind generation capacity begins to exceed 1100 MW (AESO, 2010 b). The AESO developed six long term options for stakeholder discussion: rely on EMMO; increase regulating reserve volumes; refine short term wind integration options (modifying WPM to a market based solution and developing a new ancillary service to replace the use of contingency reserves); develop a ramping service; develop a wind firming service; or develop must offer must comply (MOMC) rules for wind. These options result in various cost allocation methods, price signals, and satisfaction of system objectives, however each require additional costs to manage wind variability that would not otherwise be required with no wind capacity.

[58] Near term wind power forecasting and calculations of ramp rate capabilities were key elements of these recommendations.

Each option was assessed by the AESO and a summary is provided in Appendix L[59]. Ultimately, the options to responding to the volatility of wind generation are the direct absorption of costs by the system, the development of new services that would offset variable generation, or the subjecting of wind generators to similar rules as other generators (AESO, 2011 b). Each require trade-offs between fairness, efficiency and minimization of cost in order to maintain reliability.

Any solution to the reliability issues introduced with wind generation that imposes or allocates costs on the system must be carefully evaluated against the principles of fairness, efficiency and open competition. Operating reserves are a tool to protect the system from events that cannot be reasonably controlled (AESO, 2010 b). Treating wind variability (specifically ramp down events) as an uncontrollable event and responding with operating reserves is a benefit to wind generators at the expense of load and other generators. Managing wind ramp down using operating reserves is noted by the AESO as “consistent with the treatment for unexpected generation outages at all other facilities” (AESO, 2010 b) however the realistic expected frequency of wind variability does not suggest these events would in reality be unexpected when compared to what might be considered unexpected of a conventional generator. Should additional reserves be procured to respond to the variability of wind generation, the costs of wind integration would be inappropriately allocated and an advantage to wind generators would be provided by the system (AESO, 2011 b). This resulting cost allocation also sends inappropriate investment signals to generators and to what is valued by the system. If wind generators are required to pay for their own integration costs then they are more likely to design more efficient solutions to manage variability on the system (or not enter the market). Having costs allocated to load and other generators does not send the correct incentives to develop a solution for cost reduction, which based on the options presented by the AESO in Appendix L, would imply that it does not meet the objectives of fairness or efficiency.

As the need for additional reserves increases with added wind capacity, the price of their supply will increase. Regulating reserves will become especially valuable raising their price. Additional reserves procurement would also displace energy from the energy market and increase pool prices (at least in the short term). Further, it would require more units to be online and cycling at partial load which is less efficient and imposes additional costs on other generators. Current regulating reserve volumes range between 110 MW and 225 MW and are not sufficient to accommodate additional wind capacity (AESO, 2010 b). If regulating reserves are procured to balance supply and demand, system costs will increase. Further, fewer market participants will be able to participate due to the technological requirements with which providers of these reserves must be equipped. Contingency reserves currently range between 450 MW and 550 MW. If contingency reserves are procured, as recommended in the short term by the AESO, they would need to be in addition to the current minimum requirements set by the NWPP, which would also impose an additional cost on the system and displace energy from the energy market. Further, should the NWPP rule change allowing their use for wind events, the cost of activation for the use of the current minimum required contingency reserves would be imposed.

The effects of wind on the pool price and energy market are important for the costs of operating reserves in the system. In addition to displacing energy and raising its price (in the short run), the prices paid to providers of operating reserves are indexed to the pool price and therefore additionally rise. If wind depresses the pool price in the hours when the wind blows, it could be expected that it raises the pool

[59] Of these options, a new ramping service was determined to be the most positive approach (AESO, 2011 b).

price when the wind is not blowing. Higher pool prices when wind is not blowing or when demand is high may increase the opportunity cost of not offering into the energy market and would require higher operating reserve prices in order for generators to decide to offer into the ancillary services market as opposed to the energy market. The effect of this may be seen more during on-peak hours when wind and demand are higher. In addition, the value of regulating reserves will also be high if wind is especially volatile while demand is low. The EMMO will look to larger coal-fired plants to ramp up and down which they are not suited to do. Higher offer prices when wind is not blowing would also be present when reserves are required due to variable wind coming on and offline, especially as more wind is added.

With no wind in the system, the level of volatility in load would be limited to the daily, weekly or seasonal fluctuations in demand, which can generally be anticipated and the system adequately prepared, and which would be expected to grow linearly with growth in demand. Further, incremental gas-fired generation installed to meet load growth would inherently be more flexible and as new capacity enters the market and coal-fired generation retires could cause a reduction in the costs of operating reserves on the system. The balancing of supply and demand required with wind variability, either through additional operating reserves or new reserves products, imposes costs on the system and that would not be required with no installed wind capacity. The system flexibility required today due to the level of variable generation is becoming insufficient. As additional wind is added, additional costs to maintain system balance above the socially optimal level will be incurred (whether these costs are from additional operating reserves or other solutions identified in Appendix L). These costs will represent the economic value that is lost due to managing load volatility from wind capacity that would not exist in the no-wind scenario.

There are several elements to the cost summary of wind on operating reserves. As additional reserves are procured to manage wind variability, direct procurement costs will increase in relation to the level of reserves required. In the short run, this can increase the pool price due to displacement of capacity from the energy market and increase the price of operating reserves due to limited supply. Increases in pool prices would also result in increases to the cost of operating reserves due to the indexing of reserves prices to the pool price. These effects would reduce the effective reserve margin in the system and signal investment in additional capacity. If additional reserves are not procured, and until a long term solution is implemented, the value of reserves will increase as more wind capacity is added raising the cost of operating reserves. Cost increases due to the activation of contingency reserves, if allowed, would also raise reserve costs in this situation. The costs to implement a long term plan to manage wind variability (Appendix L) must also be considered. In effect, in the short run the variability of wind generation should either increase operating reserve prices until adequate volumes can be procured or increase volumes directly purchased in advance of price changes resulting in direct procurements costs. In the long run, costs of managing variability will be imposed and increase as incremental wind is added. Both of these will impose additional costs that would not be incurred if no wind capacity were installed in system. With no wind in the system, the costs of maintaining supply and demand would be limited to anticipated fluctuations in demand and contingency events. As such, each of these costs identified can be attributed to wind relative to gas-fired generation being installed. Most of these costs will begin to be felt as installed wind capacity reaches approximately 1100 MW.

4.5 Summary of Section

Each of the system operator objectives is affected by the addition of wind power in the Alberta electricity system. It has been demonstrated that the location, variability and intermittency of wind power generation in the Alberta system create reliability and efficiency issues that would not exist if no wind capacity was installed in the system and these issues increase system costs above an economically efficient level. It has been demonstrated that reliability can be more efficiently attained with less total installed generation and transmission capacity when wind is not in the system. The volatility of output from wind generation also imposes or transfers costs on load and other generators to manage reliability. Solutions to ensure reliability and balance supply and demand due to wind volatility require careful attention to the fairness and efficiency objectives of the system operator. System costs related to each of generation, transmission and operating reserves have been shown to be greater when wind capacity is installed relative to a no wind scenario. These costs represent the economic value to society that is lost from using these resources to include wind generation in the system. These costs can be aggregated to determine the required willingness to pay for the benefits of wind as a renewable source of energy.

The costs of additional generation and transmission to connect wind power are considered a deadweight loss. These reflect costs that are not required in the system to maintain reliability, which could otherwise be maintained with gas-fired generation at a lower cost. Costs of additional procurement or use of operating reserves are also considered a deadweight loss in that with no wind in the system, the costs relating to variability from wind generation would not be incurred and reliability would be maintained at a lower cost. Further, when wind is in the system and this deadweight loss exists, additional costs are transferred from wind generation to other market participants. Table 8 below summarizes the generation and transmission costs that would not be required in the system if capacity requirements had been met with gas-fired generation. Costs of operating reserves are not included as these have not been quantified, however they have been determined to be greater for wind relative to no wind (i.e. gas) due to volatility and the costs of maintaining balance of supply and demand outside predictable changes in load. As such, these costs are identified as the lower bound or minimum costs, without the relative operating reserve costs imposed by wind generation. The cost of additional capacity and transmission, less fuel savings from generation are demonstrated to be $1.38 billion to 1.57 billion (2011$) as of today, depending on which type of gas-fired generation replaces wind energy. The present value of these costs for the next five, ten and twenty years is identified in the Table 8.

Table 8: Summary of Minimum Costs Imposed by Wind (Present Value, Real 2011$)

Cumulative Cost ($ millions)	**2011**	**2017**	**2022**	**2032**
Extra Cost of Capacity and Generation due to Wind (SCGT, CCGT)	$1,099 – $1,289	$2,434 - $2,792	$3,756 – 4,244	$4,019 – 4,736
Cost of Transmission due to Wind	$280	$574	$802	-
Total Costs (without AS Costs) (SCGT, CCGT)	**$1,379 - $1,569**	**$3,008 - $3,366**	**$4,558 - $5,046**	**-**

These costs, in aggregate and including those relating to operating reserves, can be considered the minimum required willingness to pay for the benefits of wind power in Alberta identified in the introduction of this paper, (or any other benefits not mentioned). For this to hold, these benefits must not be wholly or partially obtained through other system changes such as the replacement of coal-fired generation with gas, in which case the benefits of wind would be relatively diminished and the required willingness to pay would be relatively higher. The quantification of benefits of wind power generation is difficult and based on both value judgments and arguable economic assumptions and it is not the intention of this paper to attempt to determine if these costs do or do not exceed the benefits of wind power.

The next section will assess the relative costs of wind generation to a generation facility owner (GFO). A comparison of the private and system objectives will then be made and the resulting incentives will be considered. The effects of various public policies on the system and private incentives will be analyzed in section 6 to see how these results would change under various policy or regulatory frameworks.

5.0 PRIVATE COST ANALYSIS OF WIND GENERATION

5.1 Generation Facility Owner (GFO) Objectives and Constraints

The objective of a GFO when making investment decisions is profit maximization. This includes the minimization of production costs. It is achieved by using the most economically efficient asset technology in the market which maximizes revenue, capturing high pool prices while maintaining a balance between plant efficiency and flexibility. Because GFO's are paid the hourly pool price for each MW supplied, revenue is reflected by the price of energy captured when their assets are generating. As noted previously, the pool price is reflective of supplier offers into the market and reflects either variable costs of supply or strategic offer behaviour. Revenues can also be achieved by offering to sell operating reserves. Currently, wind is neither offered for greater than $0/MWh nor able to be sold as a reserve product.

Recall how cost recovery in a competitive market occurs. As mentioned, generators generally offer energy into the energy market at variable cost, or otherwise offer in strategically to ensure they can always be dispatched (or not dispatched). Generators are paid, however, the offer price of the marginal MW dispatched. This means that generators which offered energy into the market below the marginal MW dispatched will receive a higher price for their energy than which they were willing to sell it. This generally means that if the pool price is high enough (i.e. above actual variable costs), generators providing energy can recover some fixed costs at these times. These short-run profits are used to recover capital and fixed costs in the long run and are known as scarcity rents, or inframarginal rents (Stoft, S. 2002). When installed capacity becomes excessive, energy prices will fall, and generators will fail to recover fixed costs. This signals that investment in new capacity would not be profitable and should not occur (Stoft, S. 2002 p. 121). Once investment stops and demand grows or existing plants retire, prices will rise and fixed cost recovery will begin again. If prices become too high raising short-run profits too much, there would be entrants into the market suppressing prices again.

To ensure adequate generation investment, GFO's respond to market signals including reserve margins, energy prices, and expected returns on investment, which indicate the profitability of entry into the market. They also respond to the costs of inputs for various technologies, indicating the costs of development and operation. Since most transmission is paid by consumers, GFO's must only consider transmission in relation to access, local connection costs, line losses and effects on congestion, which may limit their ability to supply energy. GFO objectives may not be met when investment signals are absent or because investments are made under risk and uncertainty. The major constraints facing the ability to meet investment objectives can include:

- uncertainty in load growth,
- market power,
- government policy or regulation (e.g. emissions limitations),
- capital cost constraints on development,
- variable fuel prices,
- inadequate transmission infrastructure to areas of preferred development,
- administrative limitations by price caps, and
- the offer behaviour and investment decisions of competitors.

Investing specifically in wind generation includes the same objectives of investing in other generation technologies with the additional objective of being "green". This objective has both advantages and costs. Advantages may include meeting emissions requirements, obtaining credits toward offsetting emissions from other assets, or promoting renewable energy for social, environmental, or public relations purposes. Relative to other technologies, wind generation has low variable costs and no fuel costs. Wind generation also faces high capital costs relative to other technologies, particularly CCGT. Constraints specifically related to wind generation include, as previously noted, its lack of control over fuel supply resulting in its intermittency and variability and ultimately limiting its capacity factor, its lower value relative to other technologies and inability to provide offers into multiple markets, and its lower capture price relative to other generating technologies[60]. Additional constraints include its low power density and limitations on land availability or suitability for use, (large land space is required relative to other technologies and remote wind locations make transmission infrastructure a potential delay in return on investment), and the uncertainty relating to O&M costs due to the relatively short operating lives of existing wind plants.

To minimize production costs and maximize profits, GFO's must consider cost, how much the units will be run, and the load they are intended to serve (Stoft, S. 2002 p. 34). As previously noted, wind generators run when wind is available, and are considered base load for commercial reasons. Their energy is supplied at $0/MWh. The factors affecting wind generation costs to a GFO are summarized in Table 9. One distinguishing feature of wind generation costs is that there are no variable fuel costs. Conventional generation, such as gas-fired generation, is reliant on fuel costs in addition to the variable costs identified below. Decommissioning costs are not generally included in the calculation of costs when assessing various technologies. These would be higher for technologies such as coal, hydro and nuclear, and lower for gas-fired and wind technologies which do not face similar requirements (Blanco, 2009).

[60] Recall capture price is the actual amount of revenue earned per MWh.

Table 9: Summary of Factors Affecting Wind Generation Costs

Source: Summarized from Blanco, 2009

Factor	Included	Issues and Uncertainties
Capital Costs (can be up to 80% of total costs)	Wind turbines, foundations, road construction, grid connections, construction, operating equipment	Capital costs affected by: inputs required to build wind turbine components in high demand in other markets (e.g. steel, copper, lead, cement, aluminum, carbon fiber); demand for wind energy and wind turbines;
Annual Fixed and Variable Costs	Operation and maintenance, land rental, insurance, taxes, administration	Not as well known as capital costs as few wind turbines have reached end of life and technology is rapidly changing
Electricity Produced	Capacity factor, based on local wind climate, turbine technical specifications, site and temporal characteristics, power generation reductions	Important factor in profitability of wind energy investments. (Cited as most important by NREL, Blanco).
Economic Assumptions	Discount rate, economic lifetime of investment, profitability of alternative investments, regulation, credits and subsidies	Not all technologies face the same uncertainty/risk and should not all use the same discount rate; changes to the costs of other technologies and price of their inputs change the attractiveness of wind energy.

As noted in the table, capital costs of wind turbines are dependent on demand for components and commodity prices. From the early 1980's to early 2000's, turbine costs decreased by a factor of four (IEA, 2008). After reaching a low in the early 2000's, "average wind turbine prices doubled through 2008" and have since declined substantially into 2011 (by about 20% in 2010 and even further in 2011) (Bolinger & Wiser, 2011). A 2011 study conducted by Bolinger and Wiser on trends in wind turbine prices found that "there is no single dominant factor that drove turbine prices higher from 2002-08 or that has yielded lower prices since that time" (Bolinger & Wiser, 2011).

Capital costs as well as capacity factors can also be reduced as turbine technology improves. "Turbine scaling increases energy capture while reducing general project infrastructure costs and landscape impacts, each of which can reduce the cost of wind energy" (Lantz & Hand, 2011). More efficient and fewer components mean a higher electricity output per unit of input, which can counter rising capital costs associated with higher commodity prices (IEA, 2008). Turbines can be designed for lower wind speeds as hub heights and rotor diameters increase. Further, "the electricity output of a turbine is roughly proportional to the rotor area, so fewer larger rotors on taller towers use the wind resource more efficiently than more numerous, smaller machines" (IEA, 2008). The NREL suggests that projections of modest cost declines are realizable and that larger levels of cost reductions will require innovation across turbine systems (Lantz & Hand, 2011). “Cost reductions on the order of 10% and capacity factor improvements on the order of 5% (for sites with annual mean wind speed of 7.25 m/s at 50 m) are achievable for turbines up to 3.5 MW. However to achieve 10% cost reduction and a 10% capacity factor improvement for turbines up to 5 MW, additional technology innovations must be developed and implemented” (Lantz & Hand, 2011).

5.2 Historic Revenue from Wind Generation in Alberta

This section will assess the revenue earned by wind generators to discuss the GFO objective of profit maximization. As price-takers supplying their energy at $0/MWh, wind generators face higher electricity price risk than other generators because they cannot control when they supply their energy nor can they influence the price they receive for it. Their supply at $0/MWh also depresses the pool price relative to the amount of wind generating by increasing the amount of demand that can be met at $0/MWh and shifting the marginal supplier left on the merit curve when wind is generating. This plays a role in the price they receive for their generation, and thus revenue earned. Wind generation thus also affects the price other generators receive in the market as all suppliers receive the same price for any given hour. Those hours when the wind blows depress the pool price and reduce revenue to all suppliers. When the wind does not blow, pool prices may rise, however wind generators do not capture these higher prices if they are not generating. Additional wind in the system will aggravate this effect, especially if correlated to current wind generation. Revenue from wind generation is generally captured most often when the pool price is lowest, as noted in Table 10. In 2011 and 2010, 53.5% and 79.5% (respectively) of wind generation captured a price between $0 and $100/MWh. The lower capture prices of wind are largely a function of wind not being dispatchable and of its must-run characteristic offering in at $0/MWh. It is also reflective of the lower value of wind generation relative to other generation types due to the timing and control of its availability, and of its inability to control price risk. As has been demonstrated, wind is generally available when demand (and price) is lower in spring and fall and not available during extreme temperatures when prices are higher due to higher demand (see Appendices F, G, and H).

The average price per MWh of energy generated by wind in 2011 was $50.28/MWh and in 2010 was $38.08/MWh. This was the lowest of any type and well below the average price for the market each year. In comparison, gas generation captured revenue well above the average pool price at $101.05/MWh and $62.06/MWh for 2011 and 2010 respectively. This is also consistent with 2009 (AESO, 2010 a). Gas generators can also be seen to on average to earn their highest percentage of revenue when the pool price is in the range of $500-$900/MWh whereas wind generators earn over half of their revenue when the pool price is between $0 and $100/MWh. When gas is broken out into peaking and CCGT, as in Table 11, a difference between gas-fired generation types emerges, however the trends discussed still hold true.

Table 10: Generation Revenue by Fuel Type for Various Pool Price Ranges
Source: 2011 and 2010 Annual Market Statistics, (AESO, 2012 a; AESO, 2011 a)

	2011			2010		
Pool Price Range	**Contribution to Average Pool Price**	**Wind**	**Gas**	**Average Pool Price**	**Wind**	**Gas**
$0 to $100/MWh	$27.57	53.5%	28.0%	$32.34	79.5%	53.8%
$100 to $150/MWh	$2.66	3.2%	3.6%	$2.17	2.9%	4.9%
$150 to $250/MWh	$3.92	4.4%	5.4%	$3.09	4.6%	7.2%
$250 to $500/MWh	$9.89	11.3%	13.9%	$5.05	7.1%	12.6%
$500 to $900/MWh	$19.88	18.6%	29.9%	$6.09	4.1%	15.8%
$900 to $999.99/MWh	$12.29	9.0%	19.2%	$2.14	1.9%	5.8%
Average Price per MWh	**$76.22**	**$50.28**	**$101.05**	**$50.88**	**$38.08**	**$62.06**

Table 11: 2011 Generation Revenue by Fuel Type for Various Pool Price Ranges[61]
Source: AESO Data Request (AESO, 2012 h)

	2011			
Pool Price Range	**Contribution to Annual Average Pool Price**	**Gas**	**Peaker**	**Wind**
$0 to $100/MWh	$27.57	23.8%	14.0%	53.5%
$100 to $150/MWh	$2.66	3.9%	3.6%	3.2%
$150 to $250/MWh	$3.92	5.9%	5.7%	4.4%
$250 to $500/MWh	$9.89	14.8%	15.3%	11.3%
$500 to $900/MWh	$19.88	32.4%	35.4%	18.6%
$900 to $999.99/MWh	$12.29	19.1%	26.0%	9.0%
Average Price per MWh	**$76.22**	**$123.88**	**$203.06**	**$50.28**

The pool prices captured by wind generators are noticeably lower than other generators and these results question the profitability of wind generation. Average capture prices by wind plant for the operating years since 2009 are displayed in Table 12[62]. These are the average pool prices earned, or captured, by these wind generators due to the timing of their generation in relation to the pool price[63]. They were calculated

[61] Cogen Average Price per MWh was $82.27
[62] Cells highlighted in orange indicate the wind plant was installed in that year. Only the hours from their commercial operation date are included. All other plants are assumed to have operated 8760 hours. Average Market Pool Price for the given year is identified as AVG PP at the bottom of each table. Castle Rock Wind Farm is not included (installed May 31, 2012).
[63] Capture prices are affected by factors other than the availability of wind, including congestion related to the plant location near other generators or transmission lines. For example, Summerview 1 and Summerview 2 are located beside each other and close to the Old Man River Hydro plant. In the spring when the hydro plant is generating, Summerview 2 is traditionally curtailed due to transmission congestion issues, as reflected by the

for each plant as the sum of (wind generation x pool price) per hour of each year divided by the sum of hourly generation for each year. If the levelized cost of wind generation is $90/MWh, as noted by the AESO in their 2012 Long Term Outlook (and otherwise assessed in section 5.3), revenues are too low to recover costs or make a return on investment for all current wind plants. This does not factor in the additional revenue some wind generators receive from third parties, such as from subsidies, offset credits, or long term contracts, however it does indicate the profitability of wind generation from generation alone. It is also clear from Table 12 that not all wind generators earn the same revenue, nor do they incur the same costs, which will vary as discussed above.

Table 12: Capture Prices for Wind Plants and Relative to both Average Market Price and Gas Capture Price (2012 YTD represents data from January 1 to June 15)

	2009	2010	2011	2012 YTD	Average Capture Price
Castle River #1 (CR1)*	$ 44.56	$ 38.57	$ 52.57	$ 37.71	**$ 43.35**
Blue Trail Wind (BTR1)*	$ 44.80	$ 37.64	$ 48.87	**$ 40.48**	$ 42.95
Ghost Pine (NEP1)*			***$ 57.23***	$ 28.25	$ 42.74
Ardenville Wind (ARD1)*		***$ 45.56***	$ 49.78	$ 31.36	$ 42.23
Cowley Ridge (CRWD)*	**$ 46.65**	**$ 39.85**	$ 50.41	$ 31.50	$ 42.10
Summerview 1 (IEW1)*	$ 43.43	$ 37.78	**$ 52.69**	$ 29.98	$ 40.97
Kettles Hill (KHW1)*	$ 43.94	$ 38.40	$ 50.82	$ 30.29	$ 40.86
Suncor Chin Chute (SCR3)*	$ 41.45	$ 39.54	$ 49.63	$ 29.47	$ 40.02
Soderglen Wind (GWW1)*	$ 43.05	$ 38.17	$ 49.93	**$ 27.30**	$ 39.61
Suncor Magrath (SCR2)*	$ 41.31	$ 39.27	$ 48.89	$ 28.95	$ 39.60
McBride Lake Windfarm (AKE1)*	$ 42.62	$ 37.60	**$ 46.02**	$ 30.59	$ 39.21
Enmax Taber (TAB1)*	**$ 40.25**	$ 39.45	$ 48.43	$ 28.49	$ 39.15
Summerview 2 (IEW2)*		**$ 36.81**	$ 50.65	$ 29.07	$ 38.84
Suncor Wintering Hills (SCR4)*			***$ 41.16***	$ 29.26	**$ 35.21**
Castle Rock Wind Farm (CRR1)*					
Average Price per MWh (Wind)	$ 42.31	$ 38.08	$ 50.28	*$ 30.11*	
Average Price per MWh (Gas)[64]	$ 56.23	$ 62.06	$ 101.05	*$ -*	
Average Price per MWh (Market)	$ 47.81	$ 50.89	$ 76.22	$ 50.54	
Annual Capacity Factor (Wind)[65]	33%	28%	33%	37%	

The highest and lowest capture prices per year are highlighted in bold font in Table 12. Pool prices varied both between wind generators and within a given generator between years. As noted in section 2.1, there are many variables affecting pool price. It is however interesting to note that, using only capture price data, there is little consistency between any one generator being more profitable relative to another. No

lower capture price for Summerview 2 relative to Summerview 1. (From discussion with ATCO Power subject matter experts)

[64] Data not available for 2012 YTD

[65] Annual wind capacity factor is calculated as the sum of (hourly generation for each year)/(8760 hours x installed capacity for each year).

generators repeatedly earn the highest or lowest relative revenue. Cowley Ridge and Castle Rock, the two plants identified as closest to the Pincher Creek weather stations in section 3.2, are consistently in the top half of revenue earners and above the average price per MWh for wind as a whole. Kettles Hill is the only other plant that was consistently above the average price per MWh for wind for the years assessed. Interestingly, Kettles Hill is relatively close to six other wind generators who do not show consistent revenue. No other plants showed consistency in revenue year over year for the period assessed, even for lower relative revenue.

The Brattle Group conducted an assessment on historic wind generator operating margins versus fixed costs for Alberta wind generation and concluded that, "without considering any revenues from monetizing its green attributes, wind generation investments have been consistently uneconomic for the past decade (up to 2010) and operating margins have not even exceeded the annual fixed cost requirement for wind generators even in one year during this period". (Pfeifenberger, J. & Spees, K. 2011 pg. 53). According to their analysis, new plant costs were relatively constant between 2000 and 2005 and then rose between 2006 to 2010 (Pfeifenberger, J. & Spees, K. 2011, Figure 35)[66]. Energy margins (representing revenues minus estimated operating costs in the energy market) also dropped off after 2008, from over $200/kW-yr to under $100/kW-yr (Pfeifenberger, J. & Spees, K. 2011, Figure 35). Unlike other conventional technologies, wind generators cannot earn revenue by selling operating reserves and operating margins are relatively lower for wind generators due to their inability to do so. Gas-fired technology provided 30.1%, 41.6% and 42.8% of regulating, spinning and supplemental reserves, respectively, in 2011 (AESO, 2012 a). Reduced operating margins have however been seen for all generation types. Their analysis suggests that the "drop in operating margins over the last two years raises the concern that the outlook of low gas prices may depress investments over the coming years despite the current need" (Pfeifenberger, J. & Spees, K. 2011p. 53). The profitability of wind power generation is dependent not only on the pool price and location of wind resources, but also on public policy and regulatory requirements. A precise assessment of revenue from wind generation is difficult because subsidies, Renewable Energy Credits (REC's), offset credits, and long-term energy contracts are not equivalent nor distributed evenly and their amounts and recipients are often unknown. The effects of some of these on effective revenues and costs of wind generators will be discussed in section 6.

In addition to earning low pool prices themselves, wind generators depress the pool price and affect the revenues of other generators. While this may reduce overall costs in the system in the short-run, it may affect fixed cost recovery of generators in the long run and signal that investment in additional supply is not profitable. In following the model used in the previous sections, Figure 10 shows variable costs for base load and peaking plants (CCGT and SCGT) that were provided in Table 1, and resulting revenues for each of these technologies. The graph simplifies three types of load: base load, load served by peaking capacity and load above the cost of running peaking capacity, using the optimal mix based on the costs of technology today[67]. If a base load plant (CCGT 300 MW) is supplying the marginal MW, the price of energy is identified at the variable cost of supplying that energy, $40.70/MWh. If a peaking plant (SCGT) is supplying the marginal MW, the price of energy is identified at the variable cost of supplying that energy, $53.30/MWh. As noted, base load would be running for all load, and at energy requirements

[66] This can be compared to the findings from Bolinger & Wiser, 2011 found on page 45

[67] This model is used to describe the theory behind the effect of wind. As previously discussed, not all suppliers offer in at their variable costs, nor do all suppliers with the same technologies have the same variable costs. This model should be seen as a simplification for the purposes of discussion.

above approximately 88% of installed capacity, peaking capacity would be used. These are then the pool prices required for each generating technology to recover variable costs and any pool prices above these costs, up to $1000/MWh, would be short-run profits or inframarginal rents allowing capital/fixed cost recovery. The red area on the graph represents inframarginal rents for base load capacity (revenue minus variable cost). The green spike represents inframarginal rents for both base load and peaking capacity. As explained in section 3.3, wind generation displaces base load generation and too much base load in the generation mix results. Wind on the system acts to change the use of peaking capacity to serve load, from 24% to 13% of load being met by peaking capacity, reducing energy supplied from peaking capacity when it was alternately the most efficient technology. Figure 10 demonstrates that this reduces the inframarginal rents for base load capacity in the short-run. This could cause some base load capacity to not recover enough revenue to pay back fixed costs and thus decide to leave the market. Over time, as more base load capacity retires, and assuming no additional installed wind capacity or changes to costs of technology, the correct amount of base load and peaking capacity will return. As more wind is added, peaking capacity would be more valuable and prices for their energy would rise (in both the energy and ancillary services markets) and may offset the low pool prices with wind. Pool prices would need to be higher to allow adequate investment in peakers in order for owners to recover capital costs. Reducing the capacity factor for base load or mid-merit gas as more wind is added, and increasing it for peakers which can more easily follow wind but which are more costly to run, can reduce revenue for the owners of base load generation, not for wind generators. Bifurcated pricing in the energy market, where offer prices are divided into two low and high segments in the merit order, could result. This could potentially be resolved once the system operator selects a long term wind plan that changes the $0/MWh offer price of wind. (There is currently a pilot project being undertaken by the AESO with two existing wind facilities to test the ability of wind generators to dispatch their energy as required by other market participants (AESO, 2012 g). The project will conclude in November 2012).

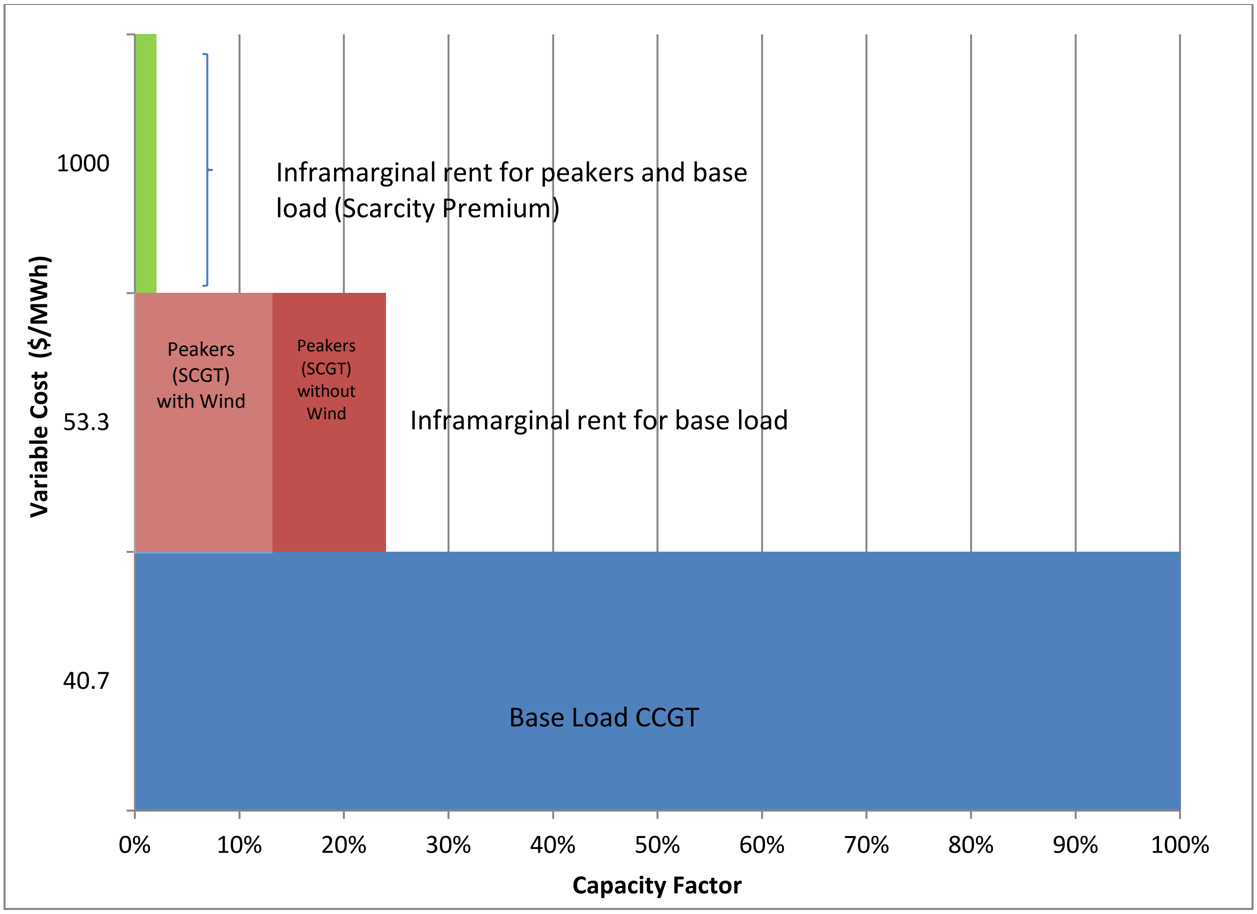


Figure 10: Variable Costs of Generation and Effect of Wind on Inframarginal Rents

5.3 Levelized Cost of Wind

This section will compare the costs of investment in wind and gas-fired generation to assess which technology can best minimize production costs. To compare relative costs of different generating technologies, a levelized cost of energy (LCOE) can be calculated. LCOE is the "constant electricity price required to cover all costs, including a specified rate of return, over the entire life of a given project" (AESO, 2012 b). For a given generation plant it is the constant real price for power that would equate the net present value of revenue from the plant's output with the net present value of the cost of production (Borenstein, 2011). Levelized costs rely on many economic and technical assumptions and results can vary widely based on the inputs chosen. The inputs and assumptions made for the present analysis are identified in detail in Tables 13 and 14, and are intended to reflect actual or potential scenarios for investment in Alberta while maintaining a simplified analysis. LCOE has been calculated for each of wind, CCGT (300 MW) and SCGT in order to compare their relative costs. Wind is compared to CCGT because wind generation is considered to be base load commercially. It can therefore be compared to the cost of investment in other base load, the most efficient alternative today being CCGT (with smaller plants marginally cheaper than larger plants based on the average cost of energy assessed in section 2.2). Wind is also compared to SCGT because the current level of wind in the system has been demonstrated to require additional peaking capacity. As such, LCOE for SCGT will be assessed with the cost of investing in additional wind.

Table 13: Levelized Cost of Energy Inputs - Fixed

	WIND	CCGT	SCGT	SOURCE/NOTES
A. Inputs constant throughout analysis but not same for all technologies				
Emissions Costs ($/tonne)	$1.80	$1.80	$1.80	$15/tonne (SGER) for 12% of plant output for generators emitting more than 100,000 tonnes of CO2 per year
Emissions Intensity (tonne/MWh)	0	0.37	0.5	AESO 2012 Long Term Outlook
Emissions Price ($/MWh)	$0.00	$0.67	$0.90	Emissions cost x Emissions intensity
Heat Rate (GJ/MWh)	0	7.4	9.8	AESO 2012 Long Term Outlook
Facility Life (years)	25	30	25	AESO 2012 Long Term Outlook
Nameplate Capacity (MW)	150	300	100	AESO 2012 Long Term Outlook
Variable O&M	$2.00	$3.70	$4.30	AESO 2012 Long Term Outlook
Depreciation Rate	50%	8%	8%	From discussion with ATCO Power
Years of Construction	2	3	3	AESO 2012 Long Term Outlook
Amortization Term	25	30	25	Taken as Facility Life for purposes of analysis
B. Inputs constant throughout analysis and same for all technologies				
Discount Rate	10%			
Construction Interest Rate	-			Not assessed
Operations Interest Rate	-			0% debt
Tax Rate	25%			AESO 2012 Long Term Outlook
Debt as % of total investment	0%			-
Equity as % of total investment	100%			-

Table 14: Levelized Cost of Energy Inputs – Variable

	WIND			CCGT			SCGT		
C. Inputs variable throughout analysis and by technology (independent)									
	HIGH	MED	LOW	HIGH	MED	LOW	HIGH	MED	LOW
Capacity Factor	41%	**35%**	27%	75.5%	**67.5%**	62%	**30%**	24%	13%
Capital Costs ($/kW - 2011)	$2,530	**$2,300**	$2,070	$1,578.50	**$1,435**	$1,291.50	$1,265	**$1,150**	$1,035
Fixed O&M ($/kWyr - 2011)	$55	**$50**	$45	$17.05	**$15.50**	$13.95	$15.40	**$14.00**	$12.60
Variable Fuel[68] ($/MWh)		**$0.00**		$59.20	**$37.00**	$25.90	$78.40	**$49.00**	$34.30

The inputs identified in Table 13 show those variables that have been fixed and are similar for all technologies and those that have been fixed but may differ between technologies. Those that vary throughout the analysis are identified in Table 14. Variable inputs identified in blue font represent the

[68] Variable fuel costs are based on gas prices of $3.50/GJ, $5.00/GJ and $8.00/GJ and Heat Rates identified in Table 13

base case scenario used in the analysis. Additional capacity factors for wind were calculated and results are shown in Appendix N. The LCOE values can be thought of as the average costs of energy previously discussed and graphed in section 2.2, taking into account financing costs and taxes. It should be noted that site specific costs vary by project and generalizations about LCOE as a whole may not hold true (Cory & Schwabe, 2009). With respect to wind, "site specific considerations such as the size of the project, economies of scale, resource quality, etc. are critical when considering the cost of wind energy" (Cory & Schwabe, 2009). Variables that will be changed in this analysis are considered to have a larger effect on LCOE than those held constant. For wind, this was established to be capacity factor by Cory & Schwabe (2009) however fuel costs are anticipated to be a large factor for gas-fired generation as well. Financing options will also differ between projects, and also play a large role in the results of LCOE calculations. Target Internal Rate of Return (IRR) values can differ depending on financing structure and terms (such as the ratio of debt to equity), on the risk and return characteristics of the project investors, and on the overall quality of the project (Cory & Schwabe, 2009). It should be assumed that any advantages in financing between technologies could improve the resulting LCOE however all financing costs, will be fixed. It should be noted that levelized costs do not factor in several important aspects required for efficiency. They take into account productions costs at the private level but do not account for any additional costs socialized to other generators, consumers or the system. They also do not always directly reflect risk in relation to uncertainty or profitability. This will be discussed again in section 6.

For this analysis, a base case scenario was established for each of wind, CCGT (300 MW) and SCGT. This base line scenario was used as a reference point to assess ranges in LCOE based on changes in capacity factor, capital costs, fixed costs and fuel costs[69]. Base case scenario values were taken for most variables from the 2012 AESO Long Term Outlook. The analysis assumed 100% equity financing. In general, the cost of debt is less than the cost of equity. It was concluded by Cory & Schwabe that the impact of technical variables (such as capacity factor and capital costs) on their estimated LCOE for wind was noticeably larger than that of financing terms (Cory & Schwabe, 2009 p. 14). For the purposes of this analysis, financing terms have been fixed. Depreciation costs are fixed but differ between wind and gas technologies due to the Capital Cost Allowance and accelerated depreciation benefits for wind generation in the federal Income Tax Regulation[70]. Emissions costs were added to both gas-fired technologies analyzed as per their calculated emissions intensities in Table 13 and their meeting the emissions limits based on size and capacity factors[71]. Only one gas scenario did not result in payment of emissions costs[72]. Fuel prices for gas fired generation were assessed at each of $3.50, $5.00 and $8.00 and capital and fixed costs were assessed based on increases or decreases of 10% from the base case scenarios. Although capital costs are paid up front and fixed costs are paid annually, they have been grouped into High, Medium and Low cost bundles to reduce the number of results in the analysis. It is however possible, that

[69] With the exception of fuel price, Cory & Schwabe, 2009 suggests these would have the greatest impact on wind LCOE.

[70] The Class 43.2 tax treatment offers an advantage of somewhere in the range of $6/MWh to $15/MWh depending on the technology it is being compared to, however it is anticipated that some forms of gas fired generation will be eligible for preferential tax treatment under Class 43.1 which would reduce the relative benefit of developing wind over gas) (From discussion with ATCO Power).

[71] It is assumed that compliance with the Specified Gas Emitters Regulation is achieved through the option to contribute $15/tonne to investment in emissions reduction projects, as discussed in section 2.4.

[72] Current emissions prices were used and it was assumed that only the payment option was used to comply with the regulation. Changes to emissions standards and their effects will be discussed in section 7.

high initial capital costs and low annual fixed costs could be incurred, (or some other combination) although this was not separately analyzed. Capacity factors were chosen based on various scenarios: for wind, various capacity factors based on previous annual Alberta values were chosen, (2007 high of 40.5%, 2010 low of 27.9%)[73]; for SCGT the AESO LTO value of 30%, as well as 24% and 13% as discussed for the Alberta energy supply mix were chosen; and for CCGT, a range of capacity factors were chosen considering reasonable adjustments based on the possible installation of additional wind displacing CCGT generation. Details on determination of capacity factors for CCGT can be found at the end of Appendix N. An Excel-based levelized cost model was used to calculate the LCOE for each set of inputs. This model was modified from a version in use at ATCO Power[74]. It represents the present value of total life cycle costs, including a true up for tax, divided by the present value of real output.

The resulting LCOE for each technology is the pool price required, on average, to recover all costs. The results of all scenarios are presented in Appendix N. Selected scenarios are presented in Table 15 to demonstrate the effects of individual variables on the relative costs of energy for each technology. The base case scenario consists of capacity factors of 35%, 67.5% and 30% for wind, CCGT and SCGT respectively, $5.00/GJ gas price, and Medium values for capital and fixed costs found in Table 14. Where one variable is identified as being changed, base case scenario values are used for the remaining inputs. If a variable is not mentioned, the base case value is used. Changes in LCOE based on individual parameters within technologies and between technologies will be discussed by scenario, as numbered in Table 15. Any conclusions are drawn based on the inputs of this particular analysis.

Table 15: Summary of selected results of LCOE calculations

		Wind	CCGT (300 MW)	SCGT
1	Base Case Scenario	$89.77	$69.79	$104.54
	Highest Cost Scenario	$127.19	$97.32	$214.25
	Lowest Cost Scenario (9% IRR)	$69.41	$53.19	$85.30
2	Low gas price with base case	$89.77	$58.92	$90.62
	High gas price with base case	$89.77	$91.54	$132.37
	High gas prices and low FC/CC for wind	$80.98		
	High gas prices and high FC/CC for wind	$98.55		
3	Lower CF for gas due to increase in wind capacity, base case for wind (35%)	$89.77	$72.39	$174.13
	Higher CF for wind due to better correlated wind (41%), base case for gas	$76.91	$69.79	$104.54
	Wind CF 37%, gas base case	$85.02		
	Wind CF 30 %, gas base case	$104.41		
	Wind CF 27%, gas base case	$115.80		
4	High CC/FC for gas, base case for wind	$89.77	$72.72	$109.86
	High CC/FC for wind, base case for gas	$98.55	$69.79	$104.54

[73] The high of 41% is also the capacity factor required to make wind the cheapest technology (Appendix G)
[74] A sample is provided in Appendix Q for the wind base case. This model follows common industry practice of levelizing cost and output.

	Low CC/FC for wind, base case for gas	$80.98		
5	37% CF, Low CC/FC for wind, 62% & 24%, low CC/FC, high fuel for gas	$76.70	$90.94	$139.02
6	37% CF, High CC/FC for wind, 62% & 24% CF, high CC/FC for gas, high fuel for gas	$93.33	$97.32	$152.33
7	30% CF, Low CC/FC for wind, 62% & 24% CF, low CC/FC for gas, low fuel for gas	$94.16	$58.32	$97.27
8	30% CF, High CC/FC for wind, 62% & 24% CF, high CC/FC for gas, low fuel for gas	$114.66	$64.70	$110.58

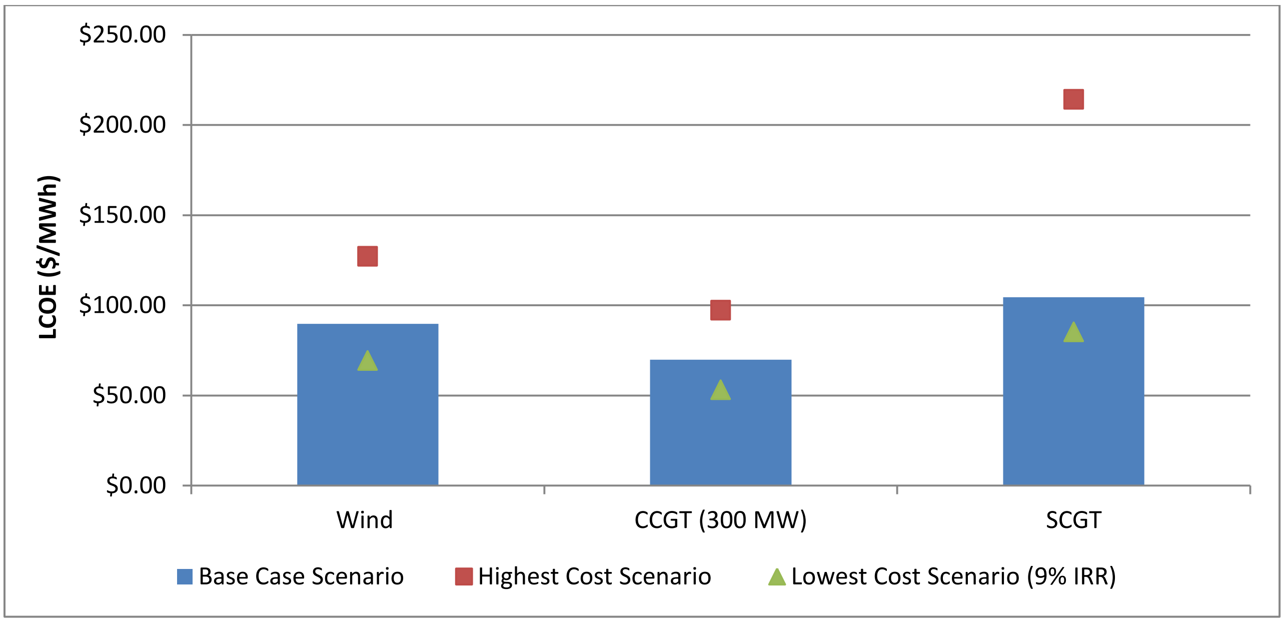


Figure 11: Levelized Costs of Energy for base case, highest cost and lowest cost scenarios

In scenario 1, the base case, highest and lowest cost cases are identified. All other results fall between these high and low costs. These costs are displayed in Figure 11. It is important to note when comparing alternate technologies that the technologies being compared may be intended to serve different parts of load and thus should not be directly compared (Borenstein, 2011). SCGT is identified as the highest cost technology (of the three assessed) however the value of the energy supplied by these units is higher than that for wind.

In scenario 2, the price of gas was changed. Low and high gas prices are $3.50/GJ and $8.00/GJ and are multiplied by the heat rates for the each gas-fired technology to determine variable fuel costs. Low gas prices, as compared to the base case for wind, do not lower the LCOE of SCGT to below wind, however they do have a large effect on the LCOE of gas-fired technology. All other things equal, a change in gas price from $3.50 to $8.00 raises the LCOE in the base case by $32.62 and $41.75/MWh for CCGT and SCGT, respectively**.** At $8.00/GJ, and considering the highest capital and fixed costs analyzed for wind

(10% above base case), keeping all other inputs constant make wind cheaper per MWh than either type of gas-fired technology analyzed. Gas price (AECO-C spot price) is currently forecast to be $5.30 in 2022 (constant price)[75] (Sproule, 2012).

In scenario 3, changes in capacity factor are assessed. This parameter was noted by the NREL to have the greatest effect on the LCOE for wind (Cory & Schwabe, 2009). Similar results appear in this analysis whereby no other variable had as significant an effect with the values chosen for the analysis (although these are reasonable they are arguably arbitrary)[76]. All other things equal, a change in wind capacity factor from 27% to 41% changes the LCOE of wind from $115.80 to $76.91/MWh, a difference of $38.39/MWh. In scenario 4, high and low capital and fixed costs are assessed for wind relative to base case gas and both high and low scenarios maintain wind between the LCOE for base case CCGT and for SCGT.

Scenarios 5 through 8 represent multivariable changes that may reflect potential real-world scenarios. These have been chosen among many possible combinations for discussion only. Others can be derived from Appendix N. These represent both favourable and unfavourable situations for wind relative to gas. In general, several points can be discussed. First, as more wind is added to the generation mix, it could incrementally displace more generation from other technologies, particularly base load, and could lower the effective capacity factor for these technologies. If this occurs, their LCOE could increase due to a lower capacity factor. It appears that capacity factors at lower levels (such as with SCGT and wind) have a relatively large effect on LCOE. Second, better or more reliable wind resources could improve the LCOE by increasing the capacity factor of wind generation, however this is outside the control of wind generators once capacity is installed. If additional wind is highly correlated (i.e. wind planned for the centre/east does not expand as planned and new capacity is installed in the south west), average wind capacity factors may remain relatively steady and smoothing effects will be limited. If it is not correlated, slight increases overall may be observed. Improvements in technology could also increase the capacity factor of wind in all potential development locations. Fuel price also has a relatively large effect on gas-fired generation, although fuel price has less impact on CCGT due to lower heat rate. High gas prices could change the relative attractiveness of wind for a private investor. Changes in capital and fixed costs (at least when bundled) seem to have a relatively smaller effect on each technology than capacity factor and fuel price. It should be noted again, that any of these technologies could become relatively more attractive if financing variables were adjusted. Financial risk is not assessed in detail in this analysis, however lower risk projects of a particular technology, either due to more certain long term costs or revenues, such as with long term energy contracts, could make one technology more attractive without any changes to technical variables. Long term contracts to supply energy, especially for renewable sources such as wind can reduce the risk of low pool prices. In addition to social commitment to purchasing "green" power, the long term cost predictability of wind generation is attractive to consumers as seen with the Alberta Schools Wind Power Project partnership with BluEarth Renewables' Bull Creek Wind Project (BluEarth, 2012).

Although SCGT has the highest costs per MWh in most scenarios, these units run when pool prices are high and can earn well above these prices when running. Wind on the other hand, which has a lower

[75] Sproule Natural Gas Price Forecast, July 31, 2012

[76] The input parameters with the largest variation between highest and lowest cost LCOE estimates generally have the greatest impact on overall costs (Cory & Schwabe, 2009)

LCOE than SCGT in most scenarios, often runs at pool prices lower than their LCOE. It appears that the LCOE of wind alone is too high for cost recovery based on capture prices identified in the previous section. The effects of subsidies and renewable energy credits on the LCOE of wind have not been added. These will be added in section 6 and will have the effect of lowering the LCOE of wind, reducing the average pool prices required for wind generators to recover costs. Table 16 summarizes the base case, high and low cost scenarios for each technology and compares these LCOE to the capture prices for wind, CCGT[77] and SCGT observed in 2011. Although the assumptions for this analysis do not likely hold true for each wind plant installed in Alberta, the results demonstrate generally that wind generation should not be profitable while investment in gas-fired generation would be profitable for most scenarios. The highest individual capture price in 2011 analyzed for an individual wind plant was $57.23/MWh for Ghost Pine, still below the lowest cost scenario for LCOE. It should be noted that pool prices were relatively high in 2011.

Table 16: LCOE and Capture Price (2011) for each technology

LCOE Scenario	Wind	CCGT (300 MW)	SCGT
Base Case Scenario	$89.77	$69.79	$104.54
Highest Cost Scenario	$127.19	$97.23	$214.25
Lowest Cost Scenario	$69.41	$53.19	$85.30
Average Price per MWh (2011)	$50.28	$123.88	$203.06

As per Table 16, wind appears relatively cheaper than SCGT per MWh. However, as they serve different types of demand in the market, these technologies capture much different prices. Without assessment of these capture prices, it would appear that wind is relatively cheaper per unit produced however, under the base case scenario and using average price per MWh for 2011, wind is operating at a loss of $39.49/MWh and SCGT is operating at a profit of $98.52/MWh. Under the base case scenario, CCGT is also operating at a profit of $54.09/MWh. Wind does have more certainty in long run costs as it is not dependent on fluctuations in fuel prices. However, although less risk exposure with respect to costs, as price-takers, wind generators are subject to greater electricity price risk with respect to revenue. Gas-fired generation has more control over the price they receive for their energy, and as previously noted, offer many of the price setting volumes in the energy market. They can increase or decrease offer prices depending on variable costs such as fuel price. If fuel prices rise, gas-fired generators can increase their offer prices and be less exposed to revenue risk. Wind generators, on the other hand, cannot influence prices, increasing their risk to revenue from low electricity prices and even depressing the electricity price while generating and capturing revenue. Wind also cannot choose when it will operate, or provide higher valued flexible generation in other markets.

5.4 Resulting Investment Incentives and Effects and Summary of Section

The objectives of the GFO are assessed by the relative costs of generation technologies and their resulting revenues from operation. Recall that the objective of a GFO when making investment decisions is profit

[77] This capture price is the average identified for “gas”. It excludes any plant considered Cogen or Peaker but plant size is not directly related to this cost.

maximization, and includes the minimization of production costs. Wind generation in the system can alter the reserve margins, energy prices and expected returns on investment, affecting the profitability of other generators and therefore the signals to enter or leave the market. Wind generation itself has also proven, thus far and without consideration for subsidies or other credits, to be unprofitable when costs are compared to revenue. GFO objectives were noted earlier to be achieved by using the most economically efficient asset technology in the market which maximizes revenue, capturing high pool prices while maintaining a balance between plant efficiency and flexibility. The low cost of CCGT and profitability of both CCGT and SCGT under current assumptions will incent investment in these technologies. The flexibility of SCGT and the relative efficiency of CCGT can also increase their individual attractiveness in meeting the needs of the long term forecast. It was also demonstrated that wind is neither flexible nor able to capture high pool prices in general due to the timing, availability and offer price of wind.

The relative attractiveness of wind could increase with high gas prices, lowered capital and fixed costs, changes to the way wind is offered into the energy market such that is does not depress the pool price (and can therefore itself capture higher pool prices), or improvements in capacity factor that would most likely be required from improvements in technology. As turbine technology improves, wind resources that have previously been considered less valuable may become sufficient to exploit and may be sufficiently uncorrelated with current wind generation to increase the average market capacity factor of wind, however this will not likely have as great an effect on individual generators. The relative attractiveness of wind could decrease with continued low gas prices, lowering capital costs for gas (although gas-fired generation is less new than wind and would likely see fewer incremental improvements due to economies of scale). Poor remaining wind resources would also reduce the relative attractiveness of wind generation investment in Alberta without improvements in technology. Wind can also increase or decrease the attractiveness of other technologies. Peaking capacity may be seen as more valuable in order to follow the volatility of wind generation. Coal-fired capacity will be seen as relatively less attractive due to the lower revenue captured as more wind is added. Additional wind can also displace CCGT in lower demand times, reducing its capacity factor and increasing its LCOE.

Market rule changes can also change the relative attractiveness of wind capacity. If market rules continue to provide an advantage to wind generators such that they are neither required to submit offers nor be held accountable for their production, (including not paying for reserves), wind may remain relatively attractive to those who can earn revenue through specific financial arrangements or outside the market. If wind generators are allocated the costs of their variability or market rule changes require them to submit firm offers as is required by other generators, development may slow until technology improves.

Government policy or regulation can also change the relative attractiveness of various energy generation technologies, as seen with coal-fired generation, which has effectively become too expensive to build. Subsidies for renewable energy, or taxes or other costs imposed on non-renewable generation will increase the relative attractiveness of wind. The costs analyzed in this section did not factor in any benefits provided to renewable energy generation with the exception of the capital cost allowance. Subsidies such as the ecoRenewable Energy program will be discussed in the next section, and its effects on both the private and social objectives of market participants will be analyzed.

The addition of new generation to meet the long term forecast will come from incentives for various generation types. Reliable and low cost sources of energy such as gas fired CCGT will continue to remain attractive to both private investors and system operators. Whatever the costs of wind power may be to a private investor however may not reflect the same objective of the system operator, who will see additional operating costs on the system. The abundance of natural gas will make gas fired generation relatively cheap to operate. Regulation on coal fired generation, for example, will likely make new investment prohibitively expensive. Subsidies for renewable generation may make wind generation more attractive for investment. Whatever the incentives in the market for investment may be, additional wind on the system will require planning to manage the its intermittency and variability. To what effect social and private incentives can achieve the same or conflicting objectives will now be discussed.

6.0 DISCUSSION AND POLICY IMPLICATIONS

6.1 Comparison of System and Private Objectives

Many factors will influence which system and private objectives can be achieved together and how wind generation in the system will affect these objectives. Recall that the objectives of the system operator are reliability, efficiency, (including minimization of social costs), fairness, and an openly competitive market. The objectives of a private GFO are profit maximization, including the minimization of production costs. The location, variability and intermittency of wind generation have been demonstrated in section 4 to have, as of 2011 imposed a cost in the range of $1.3 to $1.5 billion to society, without accounting for the additional costs imposed through reliability management or considering the effects of the costs imposed on other suppliers, particularly base load plants. It has also been demonstrated that these costs and effects will rise under the current wind development forecast, all other things equal. Further, without additional financial assistance or arrangements, wind generators do not appear to currently earn enough revenue to be profitable due to their lower capture price. Table 17 summarizes the effects of wind on the objectives of market participants in relation to gas-fired generation.

Table 17: Summary of Wind on Objectives of Market Participants versus Gas-Fired Generation

Objective	Effect of Wind Relative to Gas-Fired Generation
System Operator	
Fairness	Wind generators are not required to follow the same rules as gas and other generators.
Reliability	Wind increases volatility in supply creating increased reliability management costs on the system that do not exist under a no-wind scenario
Efficiency/Cost Minimization	Wind imposes additional generation costs due to back-up requirements, additional transmission costs due to resource location, and AS costs to manage reliability that do not exist under a no-wind scenario. They are also not required to pay the costs associated with their volatility. Gas-fired generators are not required to pay the full social cost of their emissions.
Openly Competitive	Competitiveness of wind has been assisted by government subsidy and wind generators follow different market rules than other generators. Wind generators have generally not been profitable but remain in the market.
GFO	

Profit Maximization	Wind appears to be less profitable where no government assistance or other financial incentives are present. Wind appears to be less profitable than both CCGT and SCGT.
Cost Minimization	Levelized costs are generally higher than CCGT and lower than SCGT. Wind generators are not required to pay the full social cost of their intermittency and variability. Many costs of wind generators (direct and indirect) are allocated to or funded by third parties reducing their direct costs. Gas-fired generators are not required to pay the full social cost of their emissions.
Policy	
Reduction of Carbon Emissions/ Pollution	Wind has no CO2e emissions relating to production. Gas has emissions intensities of 0.37 and 0.5 tonnes/MWh for CCGT and SCGT, respectively

Both the system operator and GFO would like to minimize their respective costs. However the minimization of private costs is not necessarily consistent with the minimization of social costs or the efficient management of system reliability. Further, the profit maximization objective of the GFO may not align with the fairness or openly competitive market objectives of the system operator. If private costs are reduced, they may simply be transferred and raise other social costs. If these costs are instead allocated to other wind producers, private costs may rise and deter investment affecting policy objectives. Unless total costs can be reduced, such that cost reductions from one perspective do not simply transfer or increase them elsewhere in the system, economic efficiency is not improved. When efficiency is not maximized, there remain gains to be exploited and it is possible to make consumers and producers collectively better off (Katz & Rosen, 1998).

Transferring costs from wind generators to other groups, or resources from other groups to wind generators, will make wind generation relatively more attractive to a GFO and may increase their relative profits, however they will have the additional effect of increasing social costs through additional generation, transmission and reliability management. The resulting effect on society will be determined by any real increase in socialized production costs relative to any real decrease in private production costs. If wind development becomes relatively more attractive, due to market or policy signals, the objectives of policy and private investment may conflict with an efficient and reliable electricity system imposing further costs on other generators and consumers.

If the private costs of wind are reduced, this could have the effects of adding more intermittent and volatile generation into the mix and of increasing the social costs identified in section 4. If wind resources in highly correlated areas are exploited to maximize profits, (as seen with Pincher Creek area wind farms) system reliability could be further compromised and volatility increased requiring additional reliability management costs. Until more flexible generation is installed in the system, the value of current peaking or other flexible generation will increase, reflecting their higher value in both the energy and ancillary services markets. The cost of peaking capacity per MWh is also higher, and the energy supplied to the market by these units would be supplied at a cost greater than that required with no wind. At the same time, price depressing effects of additional wind could also depress market prices for electricity at certain times and may signal that entry into the market is not profitable when additional base load generation will be required due to load growth.

Relative social cost reductions could occur if wind generation becomes dispatchable or firm and if any loss to suppliers is less than any gains to society. This would require market rule changes and could result in less total wind capacity installed (and more gas-fired generation investment), or in market solutions such as partnerships between wind and firm generators. Relative social cost reductions could also occur as turbine technology improves allowing suppliers to exploit new and uncorrelated wind resources that have previously been considered less valuable. As mentioned this could increase the average market capacity factor of wind and create a relatively greater smoothing effect, however this may not have as great an effect on the objectives of individual generators. Until the value of energy supplied to the system by wind increases, it will continue to affect the objectives of the system operator. This will be the case regardless of how profitable it may become to a private investor.

Ultimately, intermittent technologies such as wind do not provide the same value to the system as dispatchable generation (Joskow, 2011). In the case of Alberta, they also do not currently earn the same revenue per MWh from generation. However, the continued development of wind is occurring, as seen with the level of existing capacity and the project queue. This suggests that its value as a method of attempting to reduce carbon emissions and pollution has some worth to society.

The current Alberta electricity market has created an advantage for wind generators at the expense of other market participants for a product that ultimately provides it lower value. It has been discussed that wind generators are treated differently than other generators in the market, who are subject to Must Offer Must Comply rules. This has an impact on reliability, imposes a cost on other generators and on load, and affects the fairness and efficiency of the market. If changes to the market structure are not made to dispatch or increase the offer price of wind energy, more wind may be added to the generation mix. This could incrementally displace more generation from other technologies, particularly base load, and could lower the effective capacity factor for gas-fired technologies increasing their levelized costs. If changes to the market structure do occur, and costs are allocated to wind generators, development in wind generation may not appear as attractive and would need to be reassessed based on new costs, including the costs of storage, joint ventures with firm supply, or wind firming services.

Wind generators who do not face the true costs of their variable and intermittent generation are effectively subsidized by other generators or load. If not paying their full costs, there will be less incentive for cost reduction, and adequate solutions to improve the effects of the variability and intermittency of wind generation will not be sought to the level required to maximize economic efficiency. In addition, if wind developers do not have to pay their own costs, more wind development may occur which will increase the magnitude of the impact on social costs. If the social costs that are imposed or transferred to others by wind generators were paid by wind generators, the relative attractiveness of wind generation would be reduced. The costs paid for wind in the system were paid to resources that were not put to their best use and which could have been used in their next best alternative use. The loss of economic value to society is the result.

Although it has been described that market objectives can conflict, one market solution that could meet the objectives of both wind generators and the system operator would be developments in energy storage. Currently, fuel for conventional generators such as gas and coal can be stored and this can act as a means for these generators to control their own energy supply, and reduce their exposure to electricity price risk. Some intermittent fuels such as water for hydro plants can also be stored using dams, however this is to a lesser degree than storing fuel itself pre-use. Dams are also limited in how much water they can store. Alternately, wind cannot be controlled or stored as a fuel, and current storage of the resulting energy produced from wind generation is limited. This can be done on a small scale however it is currently expensive and still under development. Once viable options are achieved, management of wind generation volatility through the use of energy storage could create more stable output for intermittent energy sources and reduce fluctuations in output, which would reduce costs relating to back up capacity, operating reserves and intermittency (however not transmission). It would also increase the effective capacity factors of wind generators by allowing them to provide electricity to the grid when there is no wind. This may allow them to increase their revenues to levels that would make them profitable as seen with the effect of increased capacity factors on LCOE. It would also allow wind generators to comply with market rules required of other generators, and be dispatched thus not imposing costs on other market participants. Further, energy that becomes available from wind that is not required can be stored instead of curtailed. Wind generators could potentially offer into the ancillary service market with reliable energy available, which would reduce the costs of operating reserves required by wind. The cost of storage itself would need to be paid, however as storage options become more available, prices can be reduced and an assessment of relative costs may indicate its profitability. Efficiency, fairness and reliability could be improved to meet system objectives and profit maximization may be improved for the GFO (depending on the cost of storage). A small pilot project is currently underway in Alberta however it is not expected that any energy storage projects greater than 10 MW will be developed in Alberta before 2021 (AESO, 2012 c, Appendix E).

In addition to the costs imposed by the intermittency, variability and location of wind generation and the effects of separate market rules for wind generators on efficiency, various public policies can also impose additional costs for wind generation. Because of the additional costs in the system currently imposed by wind capacity, any responses to private, market or policy incentives or signals that may result in the installation of additional wind capacity can also have additional social costs, directly adding costs or raising prices elsewhere to ensure system reliability. Market signals for wind development should deter investment due to the lack of return seen when looking at cost and revenue alone, without separate market rules or additional assistance to promote renewable energy. However, public policy and regulation relating to renewable energy can also have the effect of either decreasing the cost of wind power development to a private GFO or increasing the relative cost of other generation technologies. All other things equal, additional wind capacity installed in the system in response to the promotion of renewable energy would have the same effects of other reductions in private costs of wind development, and would have additional social costs under the current circumstances.

6.2 Public Policy Options and Implications in the Promotion of Renewable Energy

The goal of public policy with respect to renewable energy is generally to address or correct for the failure of markets to price externalities imposed by non-renewable generation, namely pollution and carbon emissions. The price of electricity, which reflects a private cost, does not correctly reflect its social cost**.** However, to obtain economic efficiency, price (which would be equal to private marginal cost in a competitive market) should equal social marginal cost, where social marginal cost includes all the costs of production, including the external (un-priced) marginal damage to other people and firms (Katz & Rosen, 1998). In the presence of an externality such as carbon emissions, the price of electricity from conventional generation conveys an incorrect signal of electricity's opportunity cost to society and it is priced too low because it does not reflect all real costs. Correct price signals are not provided about the opportunity cost of electricity because no market for clean air exists which forces anyone to pay for it, and it gets overused (Katz & Rosen, 1998). When this occurs, its value is distorted and an inefficiently large quantity is consumed. The cost of electricity is based on what other things have to be given up in order to produce it. The resources for this (labour, transmission lines, substations, generating facilities, etc.) must be paid for, and all of these resources have an opportunity cost. Wind power is generally considered a social benefit as an emissions-free source of power instead of a relatively lower marginal damage cost of power production (that is, with fewer externalities and no externalities in the form of emissions from direct production)[78]. When the market fails to allocate resources efficiently due to the presence of externalities, there can be a role for government intervention. This role is to improve efficiency by ensuring these costs are priced and paid thus ensuring an efficient level of output. This role however, must be careful not to create further inefficiency and should not attempt to correct one market failure with a solution that results in a less efficient allocation of resources than was created by the original market failure.

There are many options for policy makers when addressing externalities with varying levels of efficiency. Regulation, renewable energy subsidies, renewable energy credits, emissions intensity targets, cap and trade programs, and carbon taxes are all existing or available public policy mechanisms that can be used to assist in the abatement of carbon or other externalities from power production. These mechanisms can create incentives for investment in wind power generation by increasing its relative attractiveness compared to other technologies. These policies will also indirectly affect the entire system, potentially adding costs, displacing revenue, or raising prices elsewhere to manage reliability as a greater amount of intermittent power is produced. As such, the objectives of policy can conflict with an efficient and reliable electricity system as well as with the cost minimization and profit maximization objectives of a GFO.

Policy decisions are often made based on assessment of LCOE. Although these costs are useful for a GFO, one problem with their use in guiding policy is that they only take into account productions costs at the private level and do not account for any additional costs socialized or transferred to other generators, consumers or the system. They also do not reflect the value of the energy supplied to the market, and they do not sufficiently capture risk, uncertainty, or the effects of revenue and profitability. With respect to wind generation, they may also not take into account the value of the energy that is being displaced, its relative emissions intensity, or its relative lifecycle emissions. It should also be evident, based on the varying results conducted in this analysis alone, that LCOE can ultimately be tailored to reflect what policymakers or those influencing policy would like them reflect. Costs can be overstated or understated for the gain of the party stating them, for example, to encourage or discourage subsidies. With the wide variety of choices policy makers face to attempt to equate real social cost, including marginal damage cost, with private production cost, some policies can prove efficient responses to these externalities while others prove quite inefficient. The best policies will maximize efficiency and minimize any deadweight

[78] The externalities imposed by wind have not been analyzed in the present study. The use of wind in place of fossil fuels has obvious benefits in the form of reduced carbon emissions. However, there is some debate that the life-cycle effects of wind generation, and not just the production effects, should be considered when assessing the impact of wind generation on carbon emission reductions and whether they cancel out the benefits from production. The emissions resulting from the effects of inefficient plant cycling imposed on fossil-fuel generators by wind generators are a second area of concern that would limit the benefits attained by the use of renewable power. Other externalities include the effects of wind turbine on birds, noise and local ecosystems.

loss to society from the inefficient use of resources. However the most economically efficient policies are often the least politically attractive.

The rest of this section provides a description of the economic efficiency of four current or potential public policies to address externalities from conventional generation and the promotion of wind energy. These are subsidies, renewable energy credits, current carbon pricing regulation, and carbon taxes. The effects of these policy mechanisms on the relative costs of energy will be demonstrated using the base case scenario from section 5.3. The effects of the BLIERS and CASA regulations discussed in section 2.4 will have less of an effect on new investment and will mainly affect current capacity. They may have incremental cost increases on capital for conventional generation due to improvements in technology required for new installations, however these details are currently limited. As such, these will not be specifically analyzed but may have an effect on the relative attractiveness of wind generation by imposing higher costs on gas-fired generation. Those effects related mainly to coal-fired generation will not be discussed.

Subsidies for wind and their effects

Between 2002 and 2011, the federal government provided a subsidy of $10/MWh to wind generators for their first ten years of production through the Wind Power Production Incentive (WPPI) and subsequent ecoEnergy for Renewable Power Program(IEA, 2012 a). These programs were designed to provide a production incentive for renewable power. The stated objectives included “to help Canada obtain its climate goals by achieving direct emission reductions that will result from the production of emissions-free wind energy, and reduce the cost of wind-generated electricity, thereby increasing its long term competitiveness by providing short term market opportunities that will increase existing generating capacity from wind turbines” (NRC, 2010). These subsidies had the effect of reducing the LCOE for each wind generator that was eligible by $10/MWh thus effectively reducing the amount of revenue from electricity prices required to recover capital and fixed costs (see Table 18 below). Subsidies paid by governments are funded by taxpayers. The total estimated direct cost to date of the federal subsidy for Alberta wind generators, assuming all plants installed and connected to the AIES between January 1, 2003 and March 31, 2011 received the subsidy is approximately $106 million (2011$)**.** This amount was calculated as total wind generation (in MWh) for each year beginning in 2003 and multiplying that generation by $10/MWh to find the total amount paid to wind generators per year by the subsidy. These values were then converted to 2011$ and summed[79]. The subsidy was not renewed or replaced upon its expiry in 2011 however it will continue to pay out until 2021. The costs per year can be expected to decrease as the ten year limit expires for each wind generator.

It was noted in the 2010 Renewable Energy Evaluation Report by Natural Resources Canada that “without these programs, renewable energy technologies were too costly to penetrate the market” (NRC, 2010). The WPPI and ecoENERGY subsidies are thought to be highly associated with the acceleration of the installation of renewable power between 2002 and 2009 (NRC, 2010). The NRC Report compares the cumulative amount of total wind capacity in Canada and the cumulative wind capacity commissioned through WPPI and the ecoENERGY for Renewable Power Program and shows that a steep increase in wind power production coincides with the commencement of WPPI in 2002, and tracks consistently throughout the period (NRC, 2010). While the aim of WPPI was to contribute to a reduction in, or

[79] Refer to Appendix P

avoidance of GHG production, most contributors to the report (government and industry) agreed that "it was on a very small scale" and that "additional renewable energy generation was meeting some of the increased demand for energy in the country but was not replacing any fossil fuel plants" although may replace future GHG's (NRC, 2010). The ecoEnergy program did not establish methods for measuring real world results (NRC, 2010).

Subsidies are an indirect approach to any public policy problem and do not address the root cause of the failure they are intended to resolve. Without consideration for any other effects of wind in the system, energy is not priced correctly with a subsidy. It is cheaper than the actual cost of production and over consumed. Subsidizing renewable electricity undervalues the resources being used to generate electricity which could be used in their next best alternative use. This was also the original failure the subsidy was intended to resolve where the original marginal damage cost of carbon emissions was not adequately priced, undervaluing the resources required to produce energy using conventional generation. The problem of undervaluing the resources required to produce electricity is exacerbated by reducing the cost of additional types of generation. Because costs are greater than price, someone must pay the difference and in the case of government subsidies, taxpayers pay this difference directly. Assuming no change in tax rates were required to pay for the subsidy, use of government resources to subsidize wind generation transfers resources from elsewhere where they could have be used more efficiently or not collected in the first place. The subsidy may appear to increase fairness to the wind generator, but it is an inefficient use of two sets of resources now instead of one.

The inherent inefficiency created by subsidies should be added to the existing effects of wind generation on the Alberta electricity system. The subsidy provided by the federal program is not only an inefficient allocation of resources itself, but it is being used to subsidize a second inefficient use of resources. In effect, the socialized cost incurred, or the resulting inefficiency, is two-fold. First, taxpayers are inefficiently paying once to provide the subsidy to wind generators, second – this subsidy in particular is creating the problem of separately subsidizing and promoting an intermittent and unreliable source of energy which they are then paying again to manage because additional wind capacity requires additional back-up generation, bulk transmission infrastructure and reliability management costs that would otherwise not be incurred with no wind. (Although this second effect may apply to any policy that increases the development of wind generation capacity, other policies do not necessarily increase inefficiency two-fold). As previously mentioned, if wind generators are not faced with their actual costs, just as those emitting carbon are not faced with theirs, they will not have incentives to adequately reduce costs to reflect the actual value of their resources. As such, solutions to the reliability problems created by wind's intermittency and volatility will not be addressed to the extent they should, and the problem will remain.

Whether the cost of these resources is sufficiently valued through the environmental benefits of wind generation is possible, however collective social agreement would be difficult. Although some benefits were stated to have been achieved, the emphasis is that the method used to do so has been an inefficient use of resources. Producers and consumers could be collectively better off through other means to reduce carbon emissions and as such, the use of subsidies should not be undertaken by policy makers.

Renewable Energy Credits

Another incentive for wind generation with the effect of private cost reduction is the selling of Renewable Energy Credits (REC's) to California. REC's represent the right to claim the attributes and benefits of renewable energy, (EPA, 2008). California electric utilities are legislatively required to procure 33% of their total portfolio from eligible renewable energy resources by 2020 and can create long term contracts with other utilities, including out-of-state utilities within WECC to purchase REC's to fulfill a maximum of 25% of their renewable energy requirements (CPUC, 2012 b). These contracts sell the environmental benefits generated by renewable power in Alberta, and let California utilities receive credit. REC's are sold for each MWh of electricity produced at an agreed upon price for a fixed term. They effectively reduce the LCOE for wind generators in Alberta who sell REC's and thus reduce the required electricity price needed to recover their costs. In addition to the revenue received from the energy market, wind producers receive revenue from the REC's.

The length of the contract, and thus the risk, will be part of the price agreed upon between the parties in the transaction. REC prices are confidential between parties involved, however they have been speculated to be worth between $12/MWh to $40/MWh (Herndon, 2011). There are currently 2 projects under development in Alberta that have signed long-term contracts for REC's with California utilities. The market for these contracts will slow as these utilities reach their 25% limits, however these arrangements may still affect new development in Alberta. Recently, these contracts have been limited in duration which has reduced the price these REC's receive to those who offer them, thereby reducing the financial incentives available for Alberta power producers to generate renewable energy.

The use of these contracts can increase the amount of additional wind capacity installed and thus additional costs of wind capacity and reliability management in the system. The direct cost of REC's are ultimately paid by California consumers to Alberta producers (this cost is ultimately socialized however from the perspective of the Alberta electricity system, it is not incurred). Any benefits of the renewable energy produced in Alberta would be seen in Alberta, not California, with the exception of the effects of carbon emissions on climate change which are not localized. The overriding policy that creates the market for these REC's will vary by jurisdiction. Future changes to the CPUC rules for the RPS framework, or additional implementation of their use in other jurisdictions could have a significant effect on the cost of new wind development in Alberta.

Table 18 shows the effects on LCOE from both the federal subsidies and REC's as compared to the base case scenario identified in section 5.3. The example provided demonstrates the effects of these policies on a wind plant installed in 2011 for several scenarios[80]. Moving forward, without the availability of federal subsidies for new capacity, REC's can still make wind generation relatively attractive to a GFO (depending on their price and the pool price) and indicates that these policies can have a significant effect on wind generator revenue, making them profitable in certain scenarios.

[80] This example would be required to demonstrate the installation of a plant in January, February or March in order to receive the federal subsidy as identified.

Table 18: Effects of Subsidies and Renewable Energy Credits on LCOE

EXAMPLE FOR A WIND PLANT INSTALLED IN 2011[81] AGAINST BASE CASE			
LCOE Scenario	**Wind**	**CCGT (300 MW)**	**SCGT**
Base Case Scenario	**$89.77**	**$69.79**	**$104.54**
Federal Subsidy ($10/MWh)	$79.77		
REC Price $12/MWh and Subsidy	$67.77		
REC Price $40/MWh and Subsidy	$39.77		
REC Price only $15/MWh	$74.77		

Prices on Carbon Emissions

If un-priced inputs are creating lower costs for conventional generators, undervaluing the resources required for the production of electricity and making wind production costs relatively higher, pricing the externality would be a more direct approach to addressing the problem of carbon emissions. There are several approaches to pricing carbon, such as regulation, cap and trade systems, and direct taxation. Alberta's GHG Emission Reduction program and a tax on carbon will be discussed below.

Greenhouse Gas Emission Reduction Program

Under the Alberta *Specified Gas Emitters Regulation* Greenhouse Gas Emission Reduction Program, generators outputting more than 100,000 tonnes of CO2e per year must reduce emissions by 12% per year below 2003-2005 baseline output. "Initial, unaudited compliance results show that companies have made 10.1 million tonnes (MT) of reductions in 2011, which contributes to a total of 33.6 MT of reductions to date through operational changes and investing in verified offsets created by other Alberta projects" (Government of Alberta, 2012).

This regulation provides for four options to comply thus allowing generators to select their own compliance option. To comply, generators can improve efficiency, contribute $15/tonne of CO2e to invest in emissions reductions projects, purchase offset credits from other projects such as renewable energy projects, or purchase performance credits from those who exceeded their 12% GHG reduction target (Pfeifenberger, J. & Spees, K. 2011). Offset credits from other projects are currently worth about $8/MWh to $10/MWh (AESO, 2012 b). These are sold to emitters at confidential negotiated prices however they would be expected to be less than $15/tonne. As of 2009, there were approximately 4090 MW of gas and 6060 MW of coal plants subject to this regulation (Pfeifenberger, J. & Spees, K. 2011). It is expected that the requirements for coal-fired generators in this regulation will be replaced by the federal *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* and that a federal policy will also be developed for gas-fired generators in the future (AESO, 2012 b). The limited plant output covered by this regulation (12%) and the small increases in variable costs that will ultimately be incurred limit the effects of this regulation on relative costs of alternate technologies. The current design is due for review in 2014.

[81] 2011 is used to assess with 2011$ as used for inputs and subsidy availability in 2011

The limitation on the effectiveness of this carbon pricing method is that its scope applies to only 12% of annual emissions. It therefore does not price the entire externality or marginal damage cost resulting in resources remaining undervalued. It also only applies to large emitters who emit greater than 100,000 tonnes per year. The current price on emissions from this regulation was included in the LCOE calculations from section 5.3 and it was assumed that no other options were chosen to meet the regulatory requirements. If this assumption is maintained, and the current price of carbon is increased, as shown in Table 19, only a relatively negligible increase in LCOE will occur due to the limited scope of the regulation. If instead offsets are purchased from approved wind generators, they would work in the same way as REC's, reducing the LCOE of a wind generator by $8 to $10/MWh and raising the LCOE for those generators purchasing them by amounts less than those expected with the $15/tonne contribution. The cost of these offset credits would be borne by conventional generators who purchase them and would be added to their LCOE. These are also demonstrated in Table 19 and their effects are assessed in combination with other revenue sources. Offsets are valued at $14/tonne in the example. Calculations for Table 18 are detailed in Appendix O.

Table 19: Effects of Increased Carbon Pricing under SGER on LCOE

INCREASE IN CARBON PRICE AGAINST BASE CASE[82]			
LCOE Scenario	**Wind**	**CCGT (300 MW)**	**SCGT**
Base Case Scenario	**$89.77**	**$69.79**	**$104.54**
Increase to $30/tonne CO2e for 12%		$70.46	$105.44
Increase to $45/tonne CO2e for 12%		$71.12	$106.34
Increase to $60/tonne CO2e for 12%		$71.79	$107.24
EXAMPLE FOR A WIND PLANT INSTALLED IN 2011 AGAINST BASE CASE WITH OFFSET CREDIT[83]			
LCOE Scenario[84]	**Wind**	**CCGT (300 MW)**	**SCGT**
Base Case Scenario	**$89.77**	**$69.79**	**$104.54**
Federal Subsidy ($10/MWh) + $9 Offset	$70.77	$70.41	$105.38
REC Price $12/MWh and Subsidy + $9 Offset	$58.77		
REC Price $40/MWh and Subsidy + $9 Offset	$30.77		
REC Price only $15/MWh + $9 Offset	$65.77		
$9 Offset only	$80.77		

Carbon Tax

Another way to price carbon is through a carbon tax. There is currently no such tax in place in Alberta or Canada, however this approach could improve economic efficiency while reducing carbon emissions. In general, taxes, like subsidies, alter prices and change the value of resources. However, in the case of a

[82] This would be an additional $0.67, $1.33 and $2.00/MWh for CCGT and $0.90, $1.80 and $2.70/MWh for SCGT.
[83] The offsets purchased at $14/tonne would add an additional $0.62/MWh and $0.84/MWh for CCGT and SCGT, respectively.
[84] Federal subsidy and REC prices as per Table 17

carbon tax, the tax corrects an existing distortion and does not further exacerbate it the way a subsidy does. This type of tax is known as a Pigouvian tax and is "levied upon each unit of pollution in an amount just equal to the marginal damage it inflicts at the efficient level of output" (Katz & Rosen, 1998). It essentially corrects for the lower input prices and reflects actual social costs to the producer. For each unit produced, suppliers must pay some cost to their inputs, and an additional cost toward the tax, forcing the them to take into account the costs of the externality they create and thus to produce at the economically efficient level (Katz & Rosen, 1998). The revenues from the tax can then be applied in a variety of ways, such as toward research and development for improvements in energy technology or to offset the effects of other taxes which are less efficient (i.e. that do not correct for a market failure). Either way, the goal of discouraging carbon emissions is attained. The tax itself is a transfer from producers to government however it results in the efficient level of production. Wind generation can become relatively more attractive as the costs of other technologies rise to reflect their actual social costs. Although this may add more wind into the system and impose or socialize costs elsewhere, it does improve efficiency with respect to policy choices to reduce carbon emissions. (Treatment of wind generators in the market can be corrected separately).

Taxes however are politically unfavourable. Politicians do not like to use them because voters do not like to pay them. They ultimately raise prices for consumers even if consumers are not paying the full cost of the resources they consume, and that is the intended effect. Taxes can also be much more visible than socialized or transferred costs otherwise imposed. One approach, which may make this option more politically favourable and change behaviour that undervalues carbon emissions, is what Steven Stoft calls an "untax". The untax works in the same way as a tax would with the exception that revenue is not given to the government, but returned in equal portions to consumers every year (Stoft, S. 2008). Its premise is that since consumers are the ultimate payers of a tax, (which just get passed on until the final consumer can no longer do so), they are refunded the carbon tax after it does what it needs to do. The effect of the tax in raising prices paid by suppliers still works and the stigma of the tax revenue handed to government is removed. Further, those using less than the average amount of carbon receive refunds greater than their relative cost of energy. Those who use more carbon, receive relatively less in refunds. Since there are winners and losers, and people will try to be winners, total consumption of carbon should fall while suppliers will also be incented to reduce emissions (Stoft, S. 2008). [85]

The effect of a tax on the relative cost of generation technologies can be seen in Table 20. This tax, applied to 100% of emissions can be shown to increase the costs of other generating technologies at comparable amounts to the previous subsidy provided to wind generators, still making wind relatively more attractive, while reducing carbon emissions directly and incurring no deadweight losses (by correcting the distortions existing in the market). Although the additional costs of wind generation in the system relating to intermittency and variability may still occur if wind is a relatively more attractive investment, the costs associated with inefficiently subsidizing wind generation are avoided and appropriate incentives for reductions in carbon emissions are provided. All generators can pay their full costs. Those that emit carbon, pay the marginal damage costs of carbon. Those that are variable and intermittent can pay the reliability management costs through equal treatment in the market (again, this

[85] The difference between this and a cap and trade program is only in who receives the refund – producers receive the refunds in a cap and trade program even though consumers still pay the "tax". (Stoft, S. 2008).

would be corrected through changes to market rules). If electricity prices rise, electricity will be valued more and consumption will decrease to the efficient level.

Table 20: Effects of Carbon Tax on LCOE[86]

CARBON TAX AGAINST BASE CASE[87]			
LCOE Scenario	**Wind**	**CCGT (300 MW)**	**SCGT**
Base Case Scenario	**$89.77**	**$69.79**	**$104.54**
Carbon Tax of $15/tonne CO2e on 100%		$75.34	$112.04
Carbon Tax of $30/tonne CO2e on 100%		$80.89	$119.54

Most of the current and politically favourable public policies focus on incentives to promote renewable energy directly (REC's, subsidies) and not reduce carbon emissions directly (pricing externalities). Subsidies and REC's have a much larger effect on LCOE than the current price of carbon in Alberta in improving the relative attractiveness of wind generation to a GFO. They also have the advantage of being less visible costs to consumers. Policies should be careful not to impose new social costs when they are intended to increase social benefits. The costs of pollution should be allocated to polluters and not offset by encouraging the use of resources for alternate technologies that cannot reliably provide electricity in Alberta and which ultimately create new costs. Although reducing private costs would be favourable in itself and reduce total costs to society, most public policies merely transfer costs from one party to another, and consumers still ultimately pay. The level of inefficiency related to these costs can be reduced or eliminated with the correct public policies.

The current benefit of renewable power is only in relation to the emissions or other externalities of conventional generation. The additional costs that are socialized with the current use of wind power generation would need to be less than the value of the benefits of wind power generation to justify their being incurred. The benefits of wind generation have not been specifically assessed in this paper, nor have attempts been made to quantify them. However, depending on the policies chosen to reduce carbon emissions, the costs associated with attaining these benefits can rise or fall, changing the level of benefits required to justify the costs imposed by wind generation. Public policies designed to promote renewable power or to price externalities may both increase the amount of installed wind generation but neither will address the market issues seen from additional wind in Alberta's energy-only market. Managing wind variability is a cost that may only be reduced by improvements in technology or changes to existing market rules, specifically those that currently provide advantages to wind generators at the expense of other generators. The cost of additional transmission infrastructure is less easily reduced and would likely be required to continue to be part of any willingness to pay for wind as a renewable energy source.

Each of the policy options discussed above increase costs in some form. But increasing costs to reflect the pricing of an un-priced input and allocating resources efficiently will help ensure subsequent costs are also allocated to the right groups and resulting incentives will properly allocate resources and promote the behaviours required to reduce carbon emissions. There will ultimately be a required willingness to pay for

[86] Calculations are detailed in Appendix O
[87] This would be an additional $5.55 and $11.10/MWh for CCGT and $7.50 and $15.00/MWh for SCGT

the additional costs imposed by wind through its location and until more efficient market solutions can be achieved, through back-up generation and reliability management costs. These costs are not required for economic efficiency or reliability and are a dead weight loss to society. They are the value lost to society due to the excess resources required for additional generation capacity, transmission capacity, and reliability management. There may however be a value gained to society through the benefits of renewable, emissions-free power generation. This must be considered against the willingness to pay for renewable energy from wind and minimized to the extent possible through improvements in technology or changes to market rules. But a cost increase is ultimately required for efficiency. This increase in cost may be perceived to be greater than it actually is because of the current under-pricing of electricity and the technologies currently valued to produce it, but it would accurately reflect the value of resources required to produce electricity. The cost of intermittency and variability, and location of wind resources may reduce efficiency but be worth the benefit of renewable energy. This determination will be based on the actual reduction in emissions relative to the choice of alternate technologies, on the externalities from the additional generation required to be ready to back-up wind, and ultimately a value judgment on the cost of emissions and climate change.

6.3 Promotion of Renewable Energy in Alberta

The additional costs imposed by wind generation in Alberta can be summarized into two parts. One, wind generation is being provided an advantage directly through subsidies or other policies that are not ultimately addressing, or sufficiently addressing the cause of the failure they are intended to address, i.e. inadequately priced carbon emissions. Two, wind generation is not a reliable source of energy and its intermittency, volatility and resource location require additional costs be incurred for a benefit that is difficult to quantify. It is being subsidized indirectly through the socialization or transfer of its production costs, sending incorrect market signals and creating costs that are ultimately an inefficient use of resources in the generation of electricity. These two costs are the result of two different inefficiencies, undervalue two sets of resources, and should be resolved by two different solutions if wind power is deemed to be a desirable technology in the attainment of lowered carbon emissions and pollution.

The value of carbon emission reductions should also be carefully assessed and should take into account that the generation displaced by wind is the generation from whatever technology the marginal MW is being generated. Depending on the time of day, this may be gas-fired generation more often than coal, especially during on-peak hours when most wind is generating in Alberta. If wind displaces gas and not coal, the benefits of reducing carbon emissions are reduced because gas-fired generation already has relatively lower emission intensities. The emissions from the cycling of conventional generators that may be required to be readily available if new reserves are procured will also reduce the relative benefits of wind generation. Although there could be additional benefits from renewable energy not mentioned in this paper, such as energy security, it would not be rational to promote wind power generation for most of its other attributes, which are precisely the attributes creating the increased costs.

The cost to society of carbon abatement, looking at the current and projected costs imposed by wind generation can be compared to other options such as a carbon tax to demonstrate that the current method is inefficient. A cost per tonne of carbon can be calculated by comparing the tonnes of emissions avoided from using wind energy with the additional costs of wind energy relative to lower cost, more reliable and firm gas-fired generation. The cost of carbon abatement can be calculated using the emissions saved by installing and operating wind generation capacity. Using the emissions intensity of 0.5 tonnes/MWh for SCGT and 0.37 tonnes/MWh for CCGT, and under the assumptions used in the analysis in section 4.2 (specifically the 35% wind capacity factor and the actual or forecasted wind capacity), Table 21 shows the emissions that are saved (not emitted) by supplying energy with wind instead of gas. The cost of these emissions reductions is the cost of the capital and fixed costs, less variable costs relative to gas-fired generation taken from section 4.2, Table 4 for generation beginning in 2000. This cost can then be divided by the emissions saved to determine a cost per MWh of carbon abatement. Table 21 shows these results in both real 2011$ and in these dollars discounted to 2011 (at 10%) for future years[88]. The table shows the cumulative costs of carbon abatement in relation to the cost of wind generation relative to the no wind scenario. If wind in the system currently imposes the additional capital and fixed costs and saves the fuel costs discussed in section 4.2, the cost of carbon abatement can be seen to be quite high.

Table 21: Cumulative cost of Carbon Abatement in Alberta under Wind Scenario Relative to Gas (No Wind Scenario)

CUMULATIVE COST OF CARBON ABATEMENT					
		2000-2011	**2000-2017**	**2000-2022**	**2000-2032**
Wind Capacity	MW	865	1,694	2,544	3,578
Wind Energy Supplied	MWh	13,521,060	35,726,565	61,247,949	110,513,970
Emissions Abated if SCGT	Tonnes	6,760,530	19,164,800	36,058,460	83,776,151
Emissions Abated if CCGT	Tonnes	5,002,792	14,181,952	26,683,260	61,994,351
CUMULATIVE COST OF CARBON ABATEMENT IF DISPLACING SCGT					
Present Value of Net Cost of Wind	2011$	$1,098,864,390	$2,434,220,573	$3,755,552,184	$4,019,384,063
Cost of Carbon Abatement	**$/Tonne**	**$162.54**	**$127.02**	**$104.15**	**$47.98**
Net Cost of Wind (Real 2011$)	$2011 (Real)	$1,292,902,668	$3,886,395,732	$7,908,921,628	$11,802,849,088
Cost of Carbon Abatement	**$/Tonne**	**$191.24**	**$202.79**	**$219.34**	**$140.89**
CUMULATIVE COST OF CARBON ABATEMENT IF DISPLACING CCGT					
Present Value of Net Cost of Wind	2011$	$1,288,835,664	$2,792,473,478	$4,244,386,544	$4,735,613,583
Cost of Carbon Abatement	**$/Tonne**	**$257.62**	**$196.90**	**$159.07**	**$76.39**
Net Cost of Wind (Real 2011$)	$2011 (Real)	$1,415,749,868	$4,228,551,037	$8,536,254,249	$13,441,333,560
Cost of Carbon Abatement	**$/Tonne**	**$282.99**	**$298.16**	**$319.91**	**$216.82**

[88] The present value and real 2011$ costs identified for 2011 are not the same because of the inclusion and discounting of costs for the years 2000 to 2010.

The present value (discounting past years) of carbon abatement today is demonstrated to be $162.54/tonne for SCGT and $257.62/tonne for CCGT. A difference is noted when comparing the cost of carbon abatement for displacement of CCGT emissions versus SCGT emissions. The cost of carbon abatement is noticeably higher when wind displaces CCGT generation. This is because CCGT has a lower emissions intensity than SCGT and operates more efficiently (has a lower heat rate). If wind generation in Alberta is more likely to displace CCGT than SCGT due to its location in the energy market merit order (EMMO), the cost of carbon abatement is more likely to be on the higher side of the range shown for CCGT and SCGT and reflect the displacement of generation from CCGT. This reduces the relative benefit of wind as a method to abate carbon emissions.

If this cost of carbon abatement is compared to a carbon tax, which may be set at an amount such as $15/tonne or $30/tonne, as seen or discussed for other markets, the actual cost of carbon abatement is quite high under the current scenario. Whether the emissions reductions seen with a carbon tax would necessarily equal the tonnes reduced using wind energy has not been assessed. However, the economics and incentives of the carbon tax would drive the correct behaviour in an efficient manner and be more likely to result in reductions in current and future emissions from conventional generation itself as opposed to only displacing these emissions with wind generation.

It is important to remember that wind power is not “free”. If benefits of wind power generation are believed to be sufficient to justify its costs, the method of achieving these benefits has still been demonstrated to be inefficient, while similar benefits could be achieved through more efficient means. Overall, the effects of wind in the Alberta electricity market alter price signals and inefficiently allocate costs. If wind generators were required to pay all their own costs today, without subsidies or credits, and without separate market rule advantages, it is likely that few, if any wind generators would be able to sustain production and would either not enter the market, or shutdown shortly after doing so. If the price of carbon rises to include marginal damage costs, those emitting carbon will find ways to reduce the costs of generation. If the price of wind generation rises to actual costs of production, those who want to generate wind will find a way to enter the market and be profitable. Those that can do neither will not enter the market, or will leave the market. Ultimately, consumers will need to pay more if prices are to more accurately reflect costs. This will allow the correct value to be placed on the resources being used to produce power. Although consumers will need to pay more, it must be for the correct goods and guide the right behaviour. With higher prices due to the pricing of carbon emissions or other pollution, consumers will not over-consume because they will face the actual costs of their consumption and inefficiency will be reduced. With lower prices due to reductions in cost for additional technologies, over-consumption will continue.

Whether any of these assumptions made in this analysis prove incorrect, or have inadvertently assumed inputs that may be unfavourable to wind generation, the illustration would remain evident that additional or incremental wind is an additional social cost that does not need to be imposed and that the resources currently being used to produce power from wind can be used more efficiently. The problem with conventional generation is that there are un-priced inputs creating negative externalities for which no one is compensated. Wind generation is a potential solution however the problem with wind generation, at least to date, is that it is intermittent and variable, imposing or socializing costs on others. These are different problems and have different solutions, however if externalities were priced and wind producers paid the full costs of their generation, (including the management of intermittent power production), and all generators were subject to the same rules, the efficient state should emerge. All power would be priced higher than it is today, consumption would be reduced because power produced would not be undervalued, innovation to reduce emissions from conventional generation and improve the intermittency and variability of wind generation may emerge, and efficiency would be improved.

7.0 SUMMARY AND CONCLUSIONS

To meet forecasted load growth and replace retiring assets in Alberta, new investment in generation capacity will be required. Additional capacity from coal will be limited due to technology requirements imposed by regulation. Capacity from gas-fired generation is attractive because of its current low cost to GFO's and its flexibility in generation. It provides revenue to GFO's and high value to the system operator relative to other technologies. Wind generation has attractive environmental attributes and is available during on-peak hours, however it is less valuable to the system operator due to its intermittency and volatility. It is also currently not the least cost option for development. Wind generation does have more certainty in long run costs as it is not dependent on fluctuations in fuel prices however wind generators cannot choose when to operate and therefore have greater revenue risk as price takers. Its inflexibility and availability only in the energy market also limit its revenue potential.

In order to promote wind generation, additional revenue is or has been available to wind generators through various means. Some of these sources are through public policies designed to promote wind generation for carbon emission and pollution reductions. They are put in place to correct for a market failure whereby the externalities of conventional generators are not adequately priced, however some of the policy responses do not directly address this failure. Policies that directly reduce the cost of wind generation are not addressing the underlying problem of the un-priced externalities of conventional generation. These policies merely attempt to balance the playing field by lowering the cost of additional sources of generation in order for them to compete with generators who do not originally pay their full costs. Further, they do not create the incentives required to change the behaviours of conventional generators or allocate to them their full social costs. However, policies that create a price for carbon or other externalities will increase the cost of conventional generation to reflect its actual social cost and will ensure the resources required to produce electricity are valued appropriately. They will subsequently make those technologies that do have to incur the costs of emissions relatively more attractive. The result of both types of policy may be increased wind capacity, however policies that create new costs and do not change behaviour increase inefficiency whereas policies that correct costs to reflect actual social costs and guide behaviours toward the ultimate policy goal are efficient and ultimately more socially desirable.

If both types of policy may ultimately result in increased wind capacity, inefficiency in the Alberta market will remain or increase due to the treatment of current wind generators by the system operator. Wind generators are currently provided an advantage over other generators even though they provide lower value energy and do not face their full costs. Wind generators impose additional generation, transmission and reliability management costs on society which results in an additional inefficient use of resources. Market rule changes are required for wind generators to be on the same playing field as other technologies. If wind generators are held accountable for the costs they impose on the system and other generators, they will have better incentive to find ways to reduce volatility or provide firm power. Energy storage (outside hydroelectric options not suited for Alberta) is an ideal option for all market participants however it is not yet commercially available and remains under development. Until private and social objectives can be achieved together, wind power generation will create reliability issues and impose additional social costs.

Market rule changes, energy storage and carbon taxes would make wind power generation an efficient investment in Alberta however these will be difficult to achieve technologically and politically. Each does however solve a separate problem currently imposed by wind generators and each can individually improve efficiency in the Alberta electricity system and market, although none alone will eliminate all of the additional social costs. With the exception of additional costs relating to transmission, which cannot be resolved unless load moves to wind resources or locational transmission pricing schemes are implemented, these solutions can help reduce the social costs of wind power generation currently seen in Alberta. Additional improvements or gains in wind turbine technology may also improve development and reliability issues by allowing wind generators to develop in low wind areas with different wind profiles, however Alberta is a relatively small market and options may remain limited even with new technology. From an investor perspective, wind generation can be sufficiently subsidized with the right combination of revenue streams, however as additional wind is integrated into the AIES, and without changes to market structure, policy or improvements in technology, additional wind in the system will increase social costs of energy production. Renewable energy is a benefit to society however its current variability and intermittency make it difficult and costly to integrate. The social costs imposed from all electricity generation should be appropriately valued and paid. The cost of energy consumption is ultimately too low and equating private and social costs of all energy technologies will require prices to increase. This will result in the most efficient allocation of resources and properly value energy in society.

8.0 APPENDICES

Appendix A Wind Plants Connected to the AIES

Appendix B Average Wind Speeds by Month, Hour, and Plant/Weather Station

Appendix C Generation as Percent of Maximum Capacity for Temperatures -40 C to 40C

Appendix D Average Generation by Wind Speed

Appendix E Average Wind Capacity Factors by Month

Appendix F Plant Costs by Technology

Appendix G Average Cost of Energy Curves for gas price of $3.50/GJ, $5.00/GJ and $8.00/GJ

Appendix H AESO Long Term Forecast – Load

Appendix I Wind Plant and Weather Station Information

Appendix J Revenue and Capacity Factors by Year and Plant

Appendix K Wind Plant Correlations – Existing and Queued

Appendix L Options for Long Term Wind Integration - Summary

Appendix M Relative Cost Calculations for Wind and No-Wind Scenarios

Appendix N Levelized Cost of Energy – Results

Appendix O Emissions Output and Pricing/Costs

Appendix P WPPI and ecoEnergy Subsidy Expenses

Appendix Q LCOE Cost Model Sample

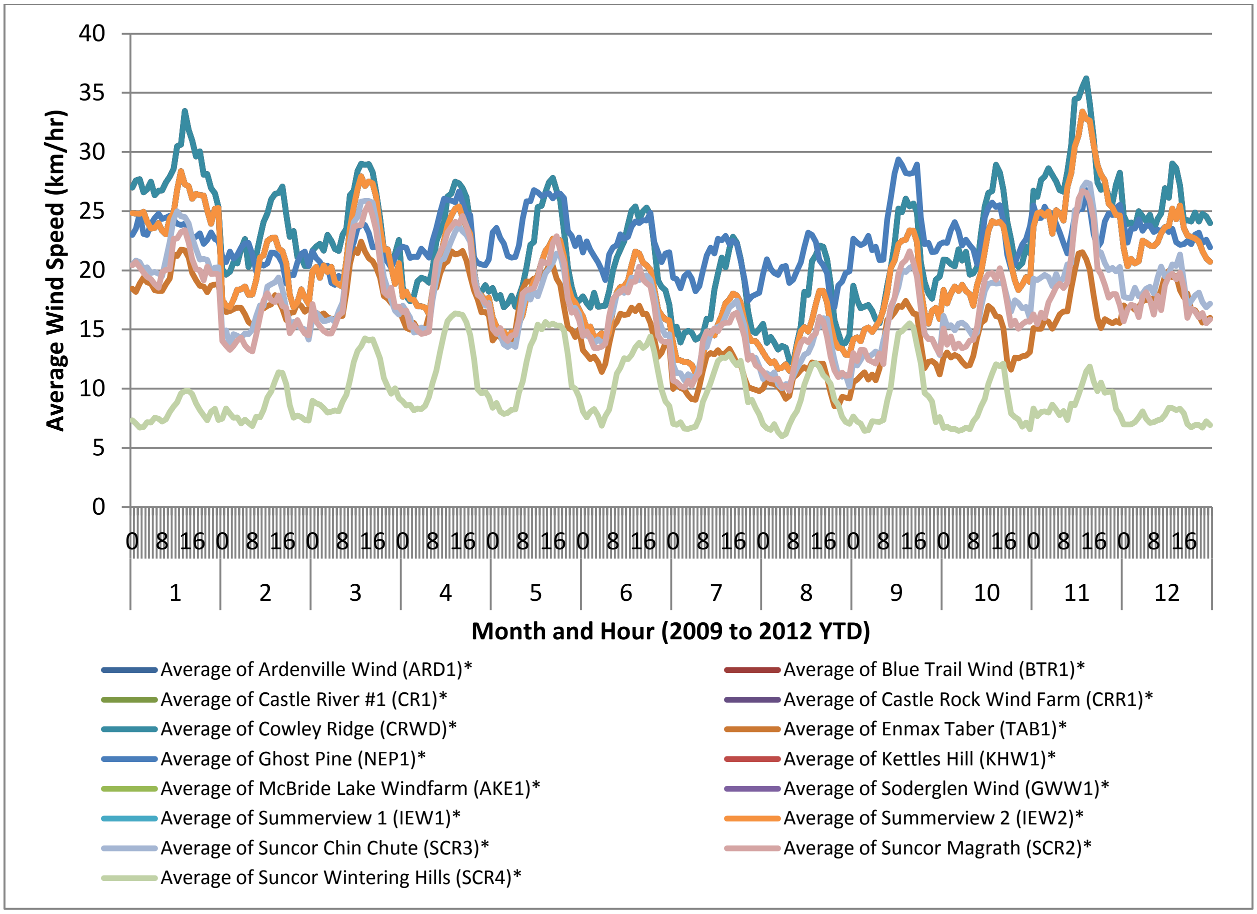
Appendix A: Alberta Wind Plants

Alberta wind plants connected to the Alberta Interconnected Electric System as at July 1, 2012 (939 MW)

Wind Plant	Size	Commercial Operation Date
Ardenville Wind (ARD1)*	66	01-Nov-10
Blue Trail Wind (BTR1)*	66	10-Sep-09
Castle River #1 (CR1)*	40	13-Dec-01
Castle Rock Wind Farm (CRR1)*	77	30-May-12
Cowley Ridge (CRWD)*	38	27-Mar-00
Enmax Taber (TAB1)*	81	27-Mar-09
Ghost Pine (NEP1)*	82	03-Jan-11
Kettles Hill (KHW1)*	63	04-Mar-06
McBride Lake Windfarm (AKE1)*	75	02-Jul-03
Soderglen Wind (GWW1)*	68	22-Aug-06
Summerview 1 (IEW1)*	69	06-Oct-04
Summerview 2 (IEW2)*	66	16-Feb-10
Suncor Chin Chute (SCR3)*	30	19-Oct-06
Suncor Magrath (SCR2)*	30	07-Sep-04
Suncor Wintering Hills (SCR4)*	88	20-Oct-11

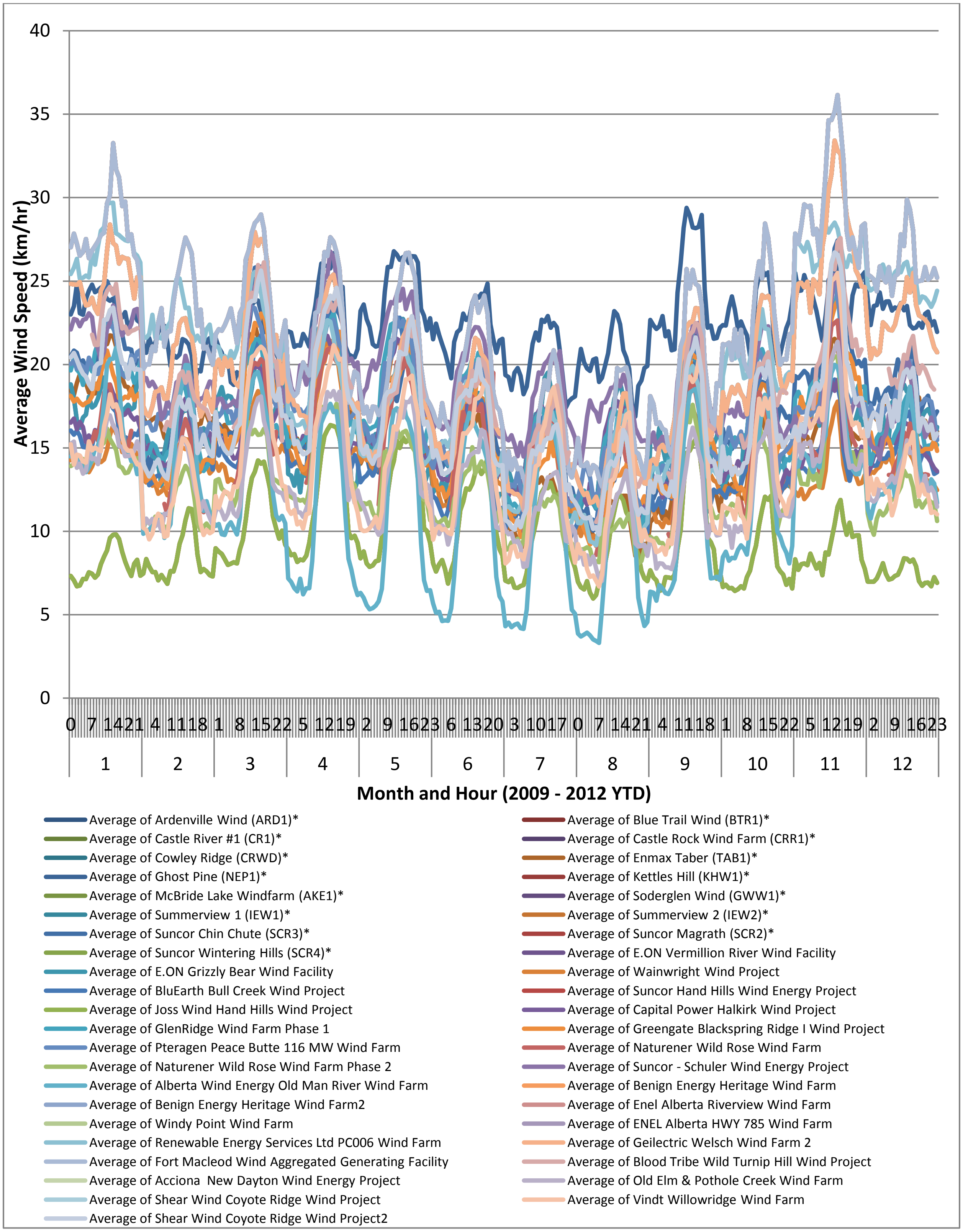
Appendix B: Average Wind Speeds by Month, Hour and Plant/Weather Station

a) Average wind speeds by month, hour and generation site for existing sites. This graph shows wind data for seven weather stations and an associated fifteen wind plants and is drawn from weather data beginning January 1, 2009 ending July 20, 2012. Months 1 through 12 and hours (shown as 0, 8, 16) are identified on the horizontal axis. Average wind speeds by month and hour are identified on the vertical axis. It appears that wind is highest during the day time (although the span of highest winds varies by month), and that wind is also highest during November and January. Wind speeds are lower in summer months, particularly July and August. These results hold for all weather station data with the exception of Drumheller East (Wintering Hills Wind Plant).



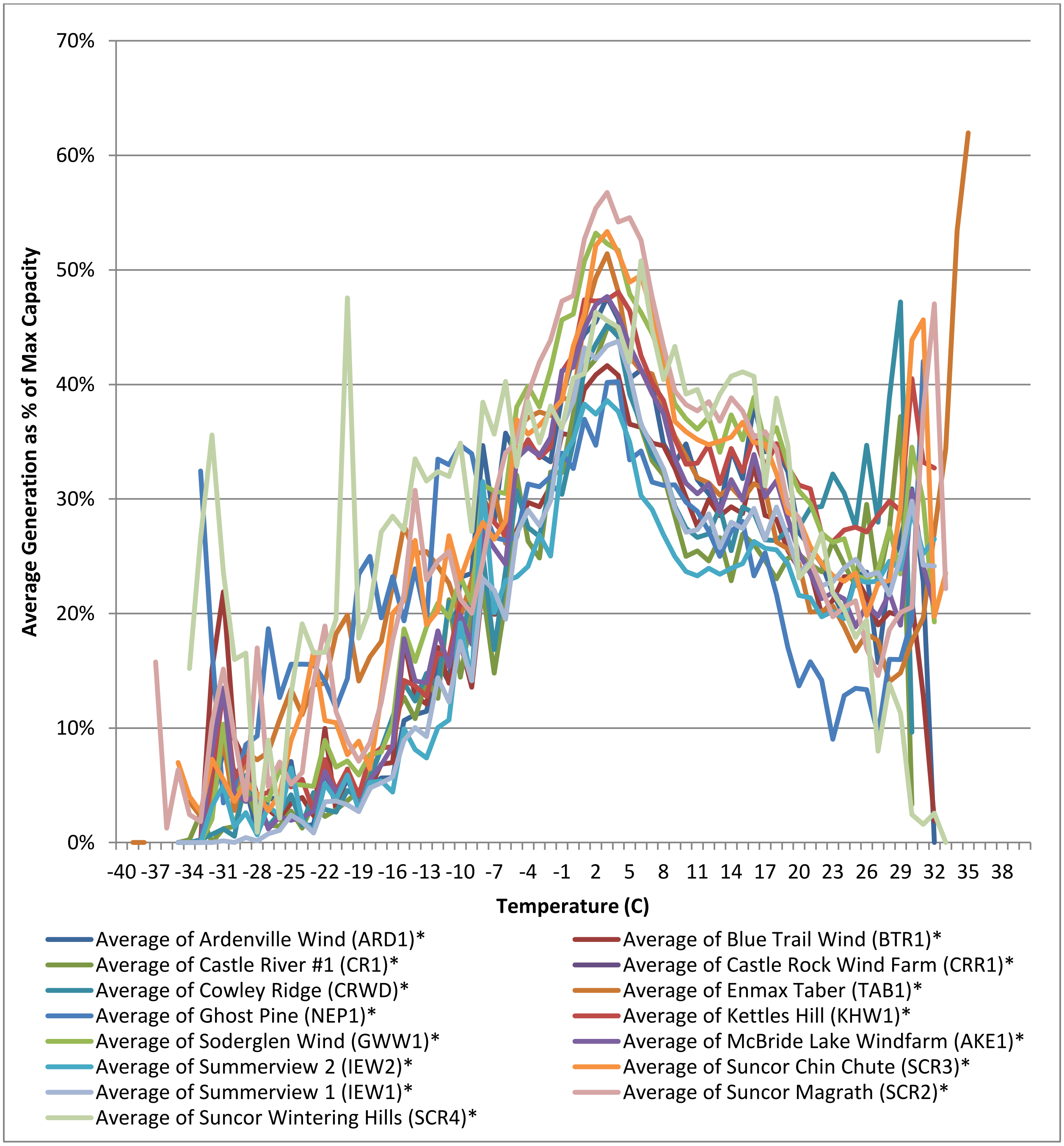
BROCKET AGDM	Ardenville, Blue Trail, Kettles Hill, McBride Lake, Soderglen, Summerview 1, Summerview 2
THREE HILLS	Ghost Pine
LETHBRIDGE DEMO FARM AGDM	Chin Chute
RAYMOND AGDM	Magrath
DRUMHELLER EAST	Wintering Hills
BOW ISLAND	Enmax Taber
PINCHER CREEK (AUT)	Castle River, Castle Rock, Cowley Ridge

b) Average wind speeds for existing and queued sites. (See Appendix I for site/weather station relationships).



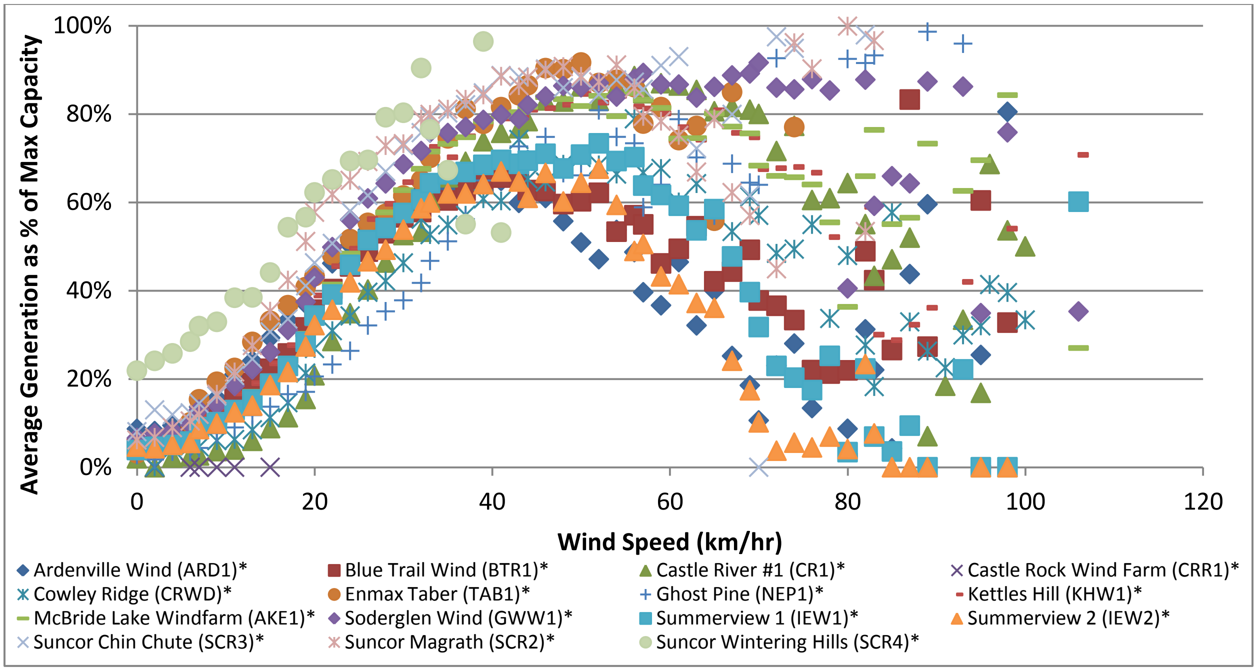
Appendix C: Generation as a Percent of Maximum Capacity for Temperatures -40 C to 40 C

Average generation by site as a percent of the maximum capacity for that site for the given temperatures between -40 C and 40 C. This graph shows wind data for seven weather stations and an associated fifteen wind plants and is drawn from weather data beginning January 1, 2009 ending July 20, 2012. Generation is averaged to normalize plant output. With the exception of several outliers, the results indicate that wind plant output peaks at temperatures between -5 C and 5 C. This is consistent with the seasonal observations noted in Figure 6.



Appendix D: Average Generation by Wind Speed

The data set consists of data from weather stations recorded by the National Climate Data and Information Archive. Deviations from the general cut-out and cut-in speeds identified can be due changes in wind speed between the location of the plant and the weather station, direction of wind or angle at which it hits the wind turbine in relation to the test conducted by the manufacturer, obstacles or other barriers between wind turbines that may reduce the speed of the wind that reaches the turbine, etc. Cut in, max output and cut out speeds were drawn from reviewing these values for Vestas, GE, Alstom, Gamesa, Mitsubishi and Siemens turbine specifications. Values chosen are representative of most turbines from these manufacturers and are for illustrative purposes only.



	km/hr	m/s
Highest Wind Speed in data set	106	29.44
General cut-out speed	90	25
General max output speed	50	13.89
Average annual wind speed denoted by AESO 2012 LTO for current wind sites	27	7.5
General cut-in speed	10.8	3
Mean Hourly Wind Speed Jan 1 2009 to July 20, 2012 for existing wind plants by closest weather station		
	km/hr	m/s
BROCKET AGDM	19.79	5.50
PINCHER CREEK (AUT)	22.49	6.25
BOW ISLAND	15.74	4.37
THREE HILLS	22.47	6.24
LETHBRIDGE DEMO FARM AGDM	17.33	4.81
RAYMOND AGDM	16.98	4.72
DRUMHELLER EAST	9.57	2.66

Appendix E: Average Wind Capacity Factors by Month

These capacity factors are summarized from the 2011 Annual Market Statistics (AESO, 2012 a). The high and low values for capacity factor over the period 2007 to 2011 are highlighted in red font. January and November see the highest capacity factors most often whereas July and August most often see the lowest.

	2007	2008	2009	2010	2011	AVERAGE
January	56.8%	51.3%	49.8%	30.5%	35.6%	44.8%
February	32.1%	42.6%	31.3%	25.9%	37.4%	33.9%
March	53.1%	43.8%	42.8%	44.6%	25.0%	41.9%
April	32.9%	40.7%	36.0%	32.5%	35.9%	35.6%
May	30.8%	28.1%	31.8%	20.5%	27.6%	27.8%
June	37.4%	25.2%	22.9%	23.2%	31.1%	28.0%
July	25.8%	20.7%	14.8%	21.8%	24.9%	21.6%
August	29.9%	27.6%	16.5%	17.7%	18.9%	22.1%
September	41.7%	18.4%	25.5%	21.3%	31.0%	27.6%
October	49.7%	38.3%	29.6%	31.2%	33.8%	36.5%
November	46.5%	50.7%	63.7%	33.5%	45.1%	47.9%
December	48.2%	35.9%	30.4%	32.4%	51.0%	39.6%

Appendix F: Plant Costs by Technology

All values in columns with white headings are taken from the AESO 2012 Long Term Outlook Appendix H, Comparative Generation Costs (AESO 2012 b).

Values in columns with blue headings were calculated as follows:

Capital Component ($/MWh) is calculated using Project Life Time (T) identified, a discount rate (r) of 10% and the following equation from Stoft, S. (2002):

Amortized Capital Cost = (r x Capital Cost)/(1-1/(1+r)^T

This value is only used in the amortization of capital cost for the purposes of calculating the Average Cost of Energy.

Variable Fuel costs are based on $5.00/GJ for natural gas and this price is multiplied by the technology's Heat Rate. (Variable fuel costs were also calculated for gas prices $3.50/GJ and $8.00/GJ and are used in Appendix G).

Fixed O&M ($/MWh) are calculated as ($/kWy)*1000/8760h.

Technology	Capacity (MW)	Capital Cost ($/kW)	Capital Component ($/MWh)	Fixed O&M ($/kWy)	Fixed O&M ($/MWh)	Variable O&M ($/MWh)	Variable Fuel ($/MWh)	Total Variable ($/MWh)
Wind	150	$2,300	$28.93	$50.00	$5.71	$2.00	$0.00	$2.00
Supercritical Pulverized Coal (BF)	450	$3,850	$45.57	$33.00	$3.77	$6.30	$9.00	$15.30
Gas Combined Cycle	300	$1,435	$17.38	$15.50	$1.77	$3.70	$37.00	$40.70
Gas Combined Cycle	800	$1,625	$19.68	$9.00	$1.03	$3.30	$36.00	$39.30
Gas Simple Cycle	100	$1,150	$14.46	$14.00	$1.60	$4.30	$49.00	$53.30

Technology	Emissions Intensity (t/MWh)	Average Capacity Factor	Heat Rate (GJ/MWh)	Project Lead Time (Yrs)	Project Life Time (Yrs)
Wind	0.00	35%	0	2	25
Supercritical Pulverized Coal (BF)	0.90	95%	9.4	4	35
Gas Combined Cycle (300 MW)	0.37	60%	7.4	3	30
Gas Combined Cycle (800 MW)	0.40	75%	7.2	3	30
Gas Simple Cycle	0.50	30%	9.8	3	25

Appendix G: Average Cost of Energy Curves

Inputs for Average Cost of Energy curves are identified in Appendix F. Variable Fuel costs are changed as identified for each of graphs b) and c).

Average Cost of Energy is calculated as: ACE = Fixed Costs/Capacity Factor + Variable Cost

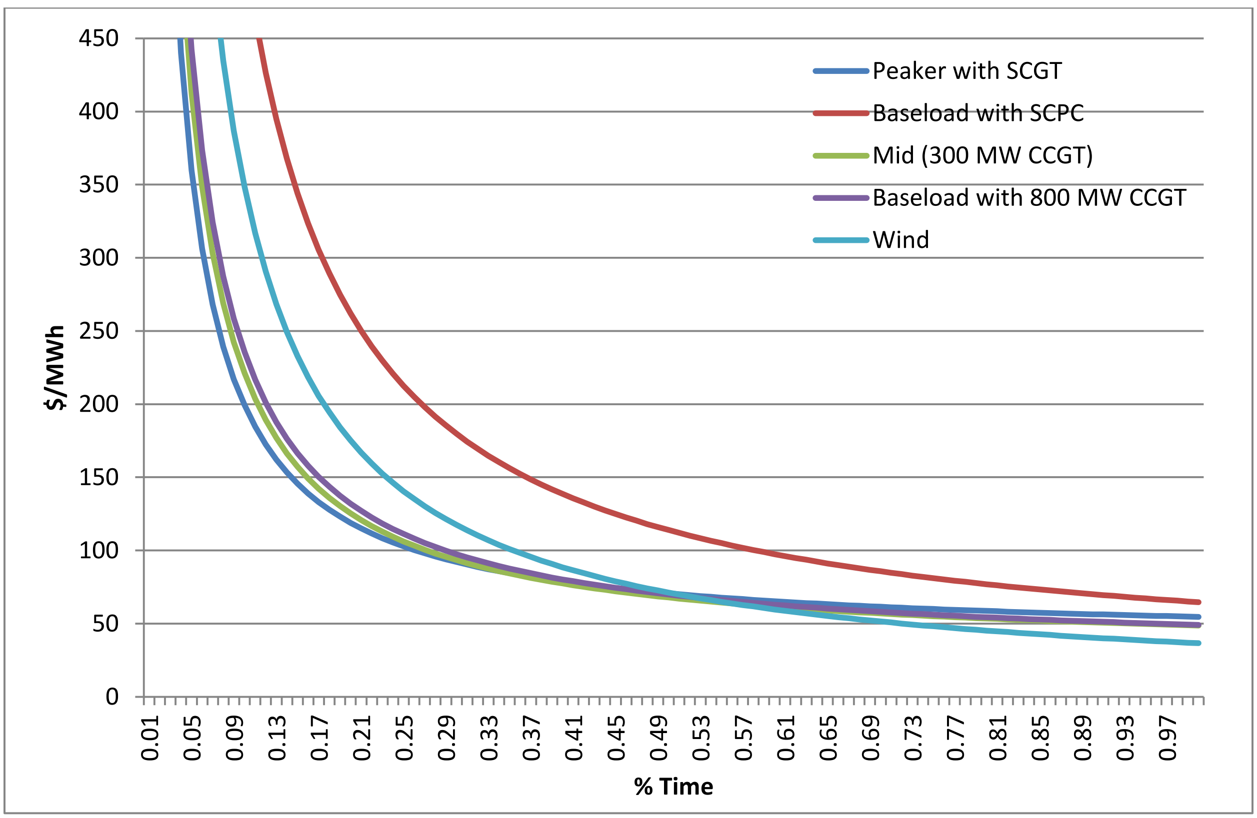
Equation taken from: Stoft, S. (2002)

Fixed costs are Fixed O&M and Amortized Capital Costs identified in Appendix F.

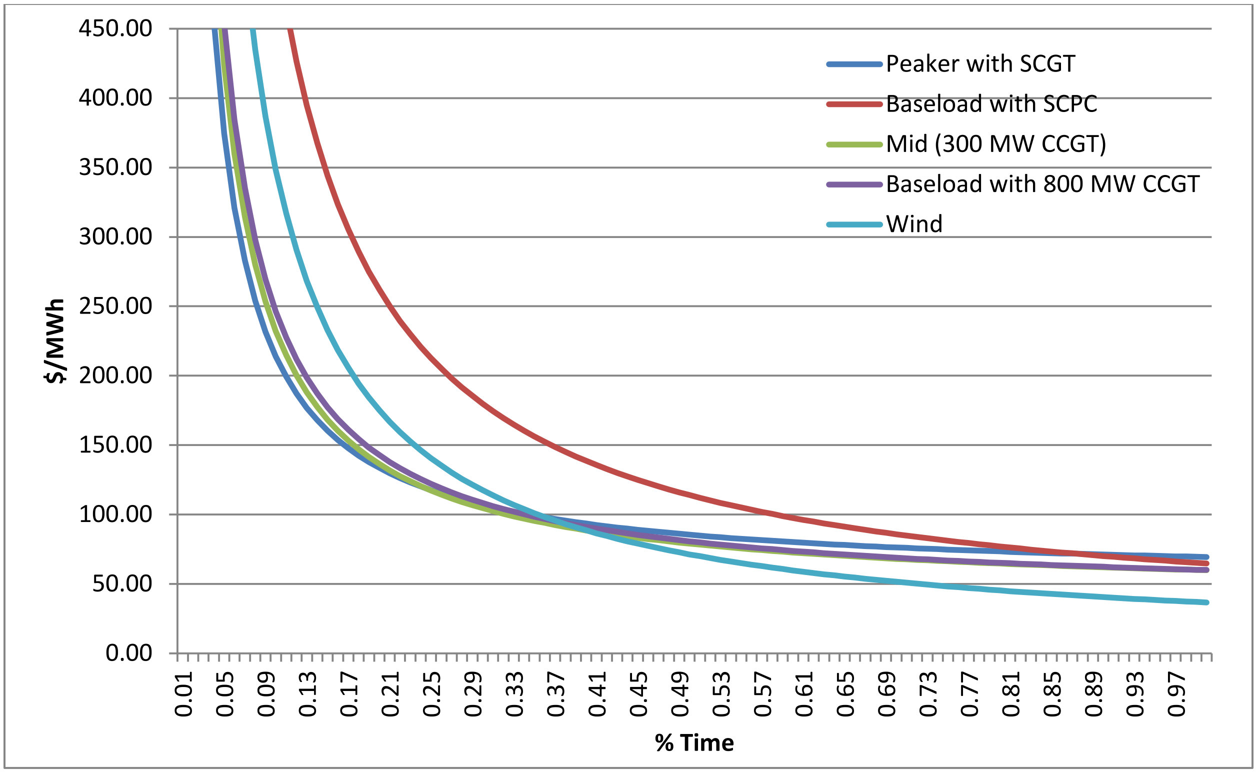
At $3.50/GJ, SCPC is not favourable for base load and only begins to become slightly more attractive than peakers at very high capacity factors around $5.00/GJ. At $8.00/GJ, SCPC becomes favourable for some base load, CCGT (300 MW) for mid-merit load and SCGT for peak load. At prices less than ~$5.50/GJ, SCPC is not favourable for any load and CCGT would be the most efficient plant type to meet base load.

At higher capacity factors, peakers become less attractive relative to other gas-fired generation however they are favourable at lower capacity factors. A CCGT plant size of 300 MW is marginally more attractive than one of 800 MW, becoming almost equally attractive at higher capacity factors.

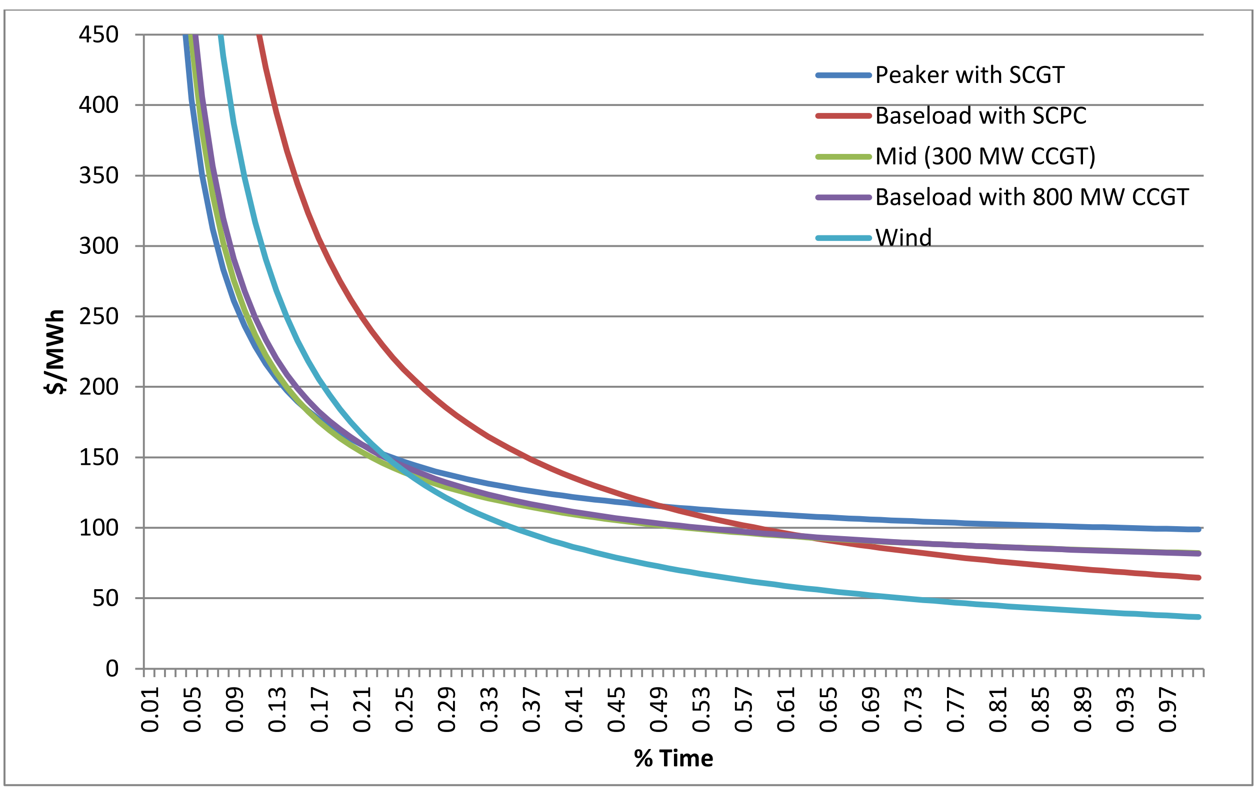
a) Average Cost of Energy Curves for gas price of $3.50/GJ



b) Average Cost of Energy Curves for gas price of $5.00/GJ



c) Average Cost of Energy Curves for gas price of $8.00/GJ



Appendix H: AESO Long Term Forecast – Load

Source: Selected forecast information from AESO 2012 Long Term Outlook, Appendix E (AESO, 2012 b)

		2011 (Actual)	2017	2022	2032
FORECAST OUTLOOK & REQUIREMENTS	AIL (GWh)	74191	92850	105501	122378
	AIL Winter Peak (MW)	10609	13005	14801	17281
	AIL Summer Peak (MW)	9608	11923	13528	15650
	15% Effective Reserve Margin (AIL Winter Peak) (MW)		1951	2220	2592
	Effective Generation Capacity required to meet peak demand + reserve margin		14956	17021	19873
CURRENT CAPACITY	Existing Generation Capacity	13659			
	Effective Existing Generation Capacity	12653			
RETIREMENTS	To 2017		834		
	To 2022			1902	
	To 2032				4658
NET CAPACITY AND FORECAST ADDITIONS	Net Effective Gen Cap after Retirements		11819	10751	7995
	Total Effective Gen Cap Required		3137	6270	11878

		2012 to 2017	2012 to 2022	2012 - 2032
FORECAST GENERATION **ADDITIONS** BY FUEL TYPE	Coal-fired	386	386	1186
	Cogeneration	837	1988	2583
	Combined Cycle	1768	2918	4818
	Simple Cycle	180	455	1105
	Hydro	0	100	1100
	Wind	829	1679	2713
	Other	131	271	1071
TOTAL ADDITIONS TO 2017	Total Additions 2012 to 2017	4131		
	Total Effective Additions 2012 to 2017	3468		

TOTAL ADDITIONS TO 2022	Total Additions 2012 to 2022		7797	
	Total Effective Additions 2012 to 2022		6404	
TOTAL ADDITIONS TO 2032	Total Additions 2012 to 2032			14576
	Total Effective Additions 2012 to 2032			11855

		2011 (Actual)	2017	2022	2032
FORECAST GENERATION **CAPACITY** BY FUEL TYPE	Coal-fired	6242	5900	4832	2876
	Cogeneration	3782	4619	5770	6365
	Combined Cycle	750	2518	3668	5568
	Simple Cycle	827	901	1176	1826
	Hydro	879	879	979	1979
	Wind	865	1694	2544	3578
	Other	314	445	585	1385
TOTAL FORECAST GENERATION CAPACITY	Total Effective Generation Capacity	12653	15269	17155	19850
	Total Installed Capacity	13659	16956	19554	23577

Appendix I: Wind Plant and Weather Station Information

Alberta weather station data was purchased from the National Climate Data and Information Archive. This information used in conjunction with approximations for geographic coordinates of current and queued wind generation facilities to determine which weather stations were closest to each facility. Coordinates were determined using either longitude and latitude or legal land descriptions converted to longitude and latitude, and compared with the longitudes and latitudes provided by the National Climate Data and Information Archive. Coordinates for individual wind plants were available on the respective company websites, through individual plant information available on the CanWEA website, and/or using Google Maps. An Alberta Legal Land Description system (Scantek system, available at: http://scantek.ca/ats.html) was used to convert legal land descriptions to longitude/latitude.

STATION	SIZE	COORDINATES (ESTIMATED)	CLOSEST WEATHER STATION
EXISTING			
Suncor Chin Chute (SCR3)*	30	49.67523 -112.34470	LETHBRIDGE DEMO FARM AGDM
Suncor Magrath (SCR2)*	30	49.42399 -112.89942	RAYMOND AGDM
Suncor Wintering Hills (SCR4)*	88	51.25291 -112.54524	DRUMHELLER EAST
Enmax Taber (TAB1)*	81	49.72062, -111.91311	BOW ISLAND
Ghost Pine (NEP1)*	82	51.88973, -113.32104	THREE HILLS
Ardenville Wind (ARD1)*	66	49.59, -113.44	BROCKET AGDM
Blue Trail Wind (BTR1)*	66	49.66, -113.49	BROCKET AGDM
McBride Lake Windfarm (AKE1)*	75	49.61879, -113.46954	BROCKET AGDM
Soderglen Wind (GWW1)*	68	49.52781 -113.50905	BROCKET AGDM
Castle River #1 (CR1)*	40	49.51, -114.02	PINCHER CREEK (AUT)
Castle Rock Wind Farm (CRR1)*	77	49.55, -113.97	PINCHER CREEK (AUT)
Cowley Ridge (CRWD)*	38	49.55133, -114.09871	PINCHER CREEK (AUT)
Kettles Hill (KHW1)*	63	49.51136, -113.82812	BROCKET AGDM
Summerview 1 (IEW1)*	69	49.58425 -113.78780	BROCKET AGDM
Summerview 2 (IEW2)*	66	49.58425 -113.78780	BROCKET AGDM
IN QUEUE		ESTIMATES	
E.ON Vermillion River Wind Facility	120	*53.12, -110.17*	LLOYDMINSTER A
E.ON Grizzly Bear Wind Facility	120	*53.37, -110.14*	LLOYDMINSTER A
Wainwright Wind Project	150	*52.85, -111.72*	KILLAM AGDM
BluEarth Bull Creek Wind Project	115	*52.53, -110.10*	CADOGAN AGCM
Suncor Hand Hills Wind Energy Project	80	*51.45, -112.14*	DRUMHELLER EAST
Joss Wind Hand Hills Wind Project	80	*51.57, -112.27*	DRUMHELLER EAST
Capital Power Halkirk Wind Project	150	*52.07, -111.45*	CORONATION CLIMATE
GlenRidge Wind Farm Phase 1	100	*50.85, -110.40*	SCHULER AGDM
Greengate Blackspring Ridge I Wind Project	300	*50.19, -112.86*	ENCHANT AGDM
Pteragen Peace Butte 116 MW Wind Farm	116	*50.16, -110.54*	SEVEN PERSONS AGDM
Naturener Wild Rose Wind Farm	200	*49.79, -110.40*	MEDICINE HAT A

Naturener Wild Rose Wind Farm Phase 2	200	*49.41, -110.21*	MEDICINE HAT RCS
Suncor - Schuler Wind Energy Project	80	*50.06, -110.26*	ONEFOUR CDA
Alberta Wind Energy Old Man River Wind Farm	47	*49.60, -114.22*	CROWSNEST
Benign Energy Heritage Wind Farm	100	49.55, -113.99	PINCHER CREEK (AUT)
Benign Energy Heritage Wind Farm	250	49.55, -113.99	PINCHER CREEK (AUT)
ENEL Alberta HWY 785 Wind Farm	235	*49.73, -113.70*	BROCKET AGDM
Enel Alberta Riverview Wind Farm	115	*49.62, -114.00*	PINCHER CREEK (AUT)
Windy Point Wind Farm	61	*49.59, -113.84*	BROCKET AGDM
Vindt Willowridge Wind Farm	100	*49.62, -113.35*	BROCKET AGDM
Renewable Energy Services Ltd PC006 Wind Farm	75	*49.64, -113.84*	WATERTON PARK GATE
Geilectric Welsch Wind Farm 2	69	49.62 -113.85	BROCKET AGDM
Fort Macleod Wind Aggregated Generating Facility	99	*49.47, -114.03*	PINCHER CREEK (AUT)
Blood Tribe Wild Turnip Hill Wind Project	150	*49.60, -112.85*	LETHBRIDGE A
Acciona New Dayton Wind Energy Project	99	*49.44, -112.37*	RAYMOND AGDM
Old Elm & Pothole Creek Wind Farm	300	*49.07, -113.39*	CARDSTON
Shear Wind Coyote Ridge Wind Project	120	*49.44, -112.56*	RAYMOND AGDM
Shear Wind Coyote Ridge Wind Project	380	*49.44, -112.56*	RAYMOND AGDM

Appendix J: Revenue and Capacity Factors by Year and Plant

Castle Rock Wind Farm is not included (installed May 31, 2012). Rows highlighted in orange indicate the wind plant was installed in that year. Only the hours from their commercial operation date are included. All other plants are assumed to have operated 8760 hours. Average Market Pool Price for the given year is identified AVG PP at the bottom of each table. Average wind capacity factor is also identified.

Calculations not evident from the tables are as follows:

REVENUE = sum of (wind generation x pool price) per hour of year

REV/MWh of Installed Generation = Revenue /sum of hourly generation for year

Capacity Factor = sum of hourly generation for year/(8760 x Installed Capacity)

2009	Installed Capacity MW	REVENUE	REV/MW of installed generation	REV/MWh of Generation (Capture Price)	Capacity Factor
Ardenville Wind (ARD1)*					
Blue Trail Wind (BTR1)*	66	$2,134,785.50	$32,345.23	$44.80	27%
Castle River #1 (CR1)*	40	$4,611,809.65	$115,295.24	$44.56	30%
Cowley Ridge (CRWD)*	38	$4,974,921.23	$130,918.98	$46.65	32%
Enmax Taber (TAB1)*	81	$9,154,112.48	$113,013.73	$40.25	32%
Ghost Pine (NEP1)*					
Kettles Hill (KHW1)*	63	$8,489,603.47	$134,755.61	$43.94	35%
McBride Lake Windfarm (AKE1)*	75	$9,614,763.44	$128,196.85	$42.62	34%
Soderglen Wind (GWW1)*	68	$10,026,299.58	$147,445.58	$43.05	39%
Summerview 1 (IEW1)*	69	$7,852,418.37	$113,803.16	$43.43	30%
Summerview 2 (IEW2)*					
Suncor Chin Chute (SCR3)*	30	$3,878,585.85	$129,286.19	$41.45	36%
Suncor Magrath (SCR2)*	30	$4,253,602.51	$141,786.75	$41.31	39%
Suncor Wintering Hills (SCR4)*					
			AVG PP	$47.81	33%

2010	Installed Capacity MW	REVENUE	REV/MW of installed generation	REV/MWh of Generation (Capture Price)	Capacity Factor
Ardenville Wind (ARD1)*	66	$1,079,177.44	$16,351.17	$45.56	25%
Blue Trail Wind (BTR1)*	66	$5,782,760.18	$87,617.58	$37.64	27%
Castle River #1 (CR1)*	40	$3,451,490.30	$86,287.26	$38.57	26%
Cowley Ridge (CRWD)*	38	$3,681,259.18	$96,875.24	$39.85	28%
Enmax Taber (TAB1)*	81	$8,299,260.15	$102,460.00	$39.45	30%
Ghost Pine (NEP1)*					
Kettles Hill (KHW1)*	63	$6,583,850.11	$104,505.56	$38.40	31%
McBride Lake Windfarm (AKE1)*	75	$7,067,056.91	$94,227.43	$37.60	29%
Soderglen Wind (GWW1)*	68	$7,754,592.93	$114,038.13	$38.17	34%
Summerview 1 (IEW1)*	69	$6,334,349.50	$91,802.17	$37.78	28%
Summerview 2 (IEW2)*	66	$3,772,055.31	$57,152.35	$36.81	20%
Suncor Chin Chute (SCR3)*	30	$3,350,067.70	$111,668.92	$39.54	32%
Suncor Magrath (SCR2)*	30	$3,523,960.12	$117,465.34	$39.27	34%
Suncor Wintering Hills (SCR4)*					
			AVG PP	$50.89	28%

2011	Installed Capacity MW	REVENUE	REV/MW of installed generation	REV/MWh of Generation (Capture Price)	Capacity Factor
Ardenville Wind (ARD1)*	66	$9,901,157.94	$150,017.54	$49.78	34%
Blue Trail Wind (BTR1)*	66	$9,563,700.58	$144,904.55	$48.87	34%
Castle River #1 (CR1)*	40	$6,007,978.36	$150,199.46	$52.57	33%
Cowley Ridge (CRWD)*	38	$4,381,718.47	$115,308.38	$50.41	26%
Enmax Taber (TAB1)*	81	$12,068,821.38	$148,997.79	$48.43	35%
Ghost Pine (NEP1)*	82	$11,016,752.92	$134,350.65	$57.23	27%
Kettles Hill (KHW1)*	63	$10,917,531.91	$173,294.16	$50.82	39%
McBride Lake Windfarm (AKE1)*	75	$10,906,255.57	$145,416.74	$46.02	36%
Soderglen Wind (GWW1)*	68	$12,354,463.13	$181,683.28	$49.93	42%
Summerview 1 (IEW1)*	69	$10,420,284.55	$151,018.62	$52.69	33%
Summerview 2 (IEW2)*	66	$9,005,239.47	$136,443.02	$50.65	31%
Suncor Chin Chute (SCR3)*	30	$5,216,438.36	$173,881.28	$49.63	40%
Suncor Magrath (SCR2)*	30	$5,517,458.30	$183,915.28	$48.89	43%
Suncor Wintering Hills (SCR4)*	88	$1,544,028.46	$17,545.78	$41.16	24%
			AVG PP	$76.22	33%

2012 **(01/01-06/15)**	**Installed Capacity MW**	**REVENUE**	**REV/MW of installed generation**	**REV/MWh of Generation (Capture Price)**	**Capacity Factor**
Ardenville Wind (ARD1)*	66	$2,866,167.26	$43,426.78	$28.49	38%
Blue Trail Wind (BTR1)*	66	$2,638,346.21	$39,974.94	$28.25	35%
Castle River #1 (CR1)*	40	$1,906,745.23	$47,668.63	$31.36	38%
Cowley Ridge (CRWD)*	38	$1,055,317.57	$27,771.51	$31.50	22%
Enmax Taber (TAB1)*	81	$3,804,392.72	$46,967.81	$30.29	39%
Ghost Pine (NEP1)*	82	$4,556,475.81	$55,566.78	$40.48	34%
Kettles Hill (KHW1)*	63	$3,227,139.50	$51,224.44	$30.59	42%
McBride Lake Windfarm (AKE1)*	75	$3,255,392.95	$43,405.24	$27.30	40%
Soderglen Wind (GWW1)*	68	$3,509,838.25	$51,615.27	$29.98	43%
Summerview 1 (IEW1)*	69	$2,801,949.76	$40,607.97	$29.07	35%
Summerview 2 (IEW2)*	66	$2,666,791.66	$40,405.93	$29.47	34%
Suncor Chin Chute (SCR3)*	30	$1,510,457.45	$50,348.58	$28.95	44%
Suncor Magrath (SCR2)*	30	$1,581,200.89	$52,706.70	$29.26	45%
Suncor Wintering Hills (SCR4)*	88	$5,798,207.98	$65,888.73	$37.71	44%
			AVG PP	$50.54	37%

Appendix K: Wind Plant Correlations – Existing and Queued

a) Correlation of Current Wind Capacity to Planned Wind Capacity

	Ardenville Wind (ARD1)*	Blue Trail Wind (BTR1)*	Castle River #1 (CR1)*	Castle Rock Wind Farm (CRR1)*	Cowley Ridge (CRWD)*	Enmax Taber (TAB1)*	Ghost Pine (NEP1)*	Kettles Hill (KHW1)*	McBride Lake Windfarm (AKE1)*	Soderglen Wind (GWW1)*	Summerview 1 (IEW1)*	Summerview 2 (IEW2)*	Suncor Chin Chute (SCR3)*	Suncor Magrath (SCR2)*	Suncor Wintering Hills (SCR4)*
E.ON Vermillion River Wind Facility	0.17	0.17	0.17	0.17	0.17	0.27	0.36	0.17	0.17	0.17	0.17	0.17	0.22	0.25	0.35
E.ON Grizzly Bear Wind Facility	0.17	0.17	0.17	0.17	0.17	0.27	0.36	0.17	0.17	0.17	0.17	0.17	0.22	0.25	0.35
Wainwright Wind Project	0.18	0.18	0.14	0.14	0.14	0.34	0.49	0.18	0.18	0.18	0.18	0.18	0.24	0.29	0.53
BluEarth Bull Creek Wind Project	0.23	0.23	0.19	0.19	0.19	0.34	0.46	0.23	0.23	0.23	0.23	0.23	0.30	0.33	0.46
Suncor Hand Hills Wind Energy Project	0.15	0.15	0.10	0.10	0.10	0.37	0.50	0.15	0.15	0.15	0.15	0.15	0.23	0.28	1.00
Joss Wind Hand Hills Wind Project	0.15	0.15	0.10	0.10	0.10	0.37	0.50	0.15	0.15	0.15	0.15	0.15	0.23	0.28	1.00
Capital Power Halkirk Wind Project	0.22	0.22	0.17	0.17	0.17	0.38	0.52	0.22	0.22	0.22	0.22	0.22	0.28	0.33	0.57
GlenRidge Wind Farm Phase 1	0.37	0.37	0.32	0.32	0.32	0.42	0.45	0.37	0.37	0.37	0.37	0.37	0.46	0.46	0.34
Greengate Blackspring Ridge I Wind Project	0.46	0.46	0.36	0.36	0.36	0.53	0.43	0.46	0.46	0.46	0.46	0.46	0.61	0.57	0.43
Pteragen Peace Butte 116 MW Wind Farm	0.47	0.47	0.40	0.40	0.40	0.62	0.40	0.47	0.47	0.47	0.47	0.47	0.57	0.56	0.35
Naturener Wild Rose Wind Farm	0.43	0.43	0.37	0.37	0.37	0.52	0.42	0.43	0.43	0.43	0.43	0.43	0.53	0.53	0.38
Naturener Wild Rose Wind Farm Phase 2	0.44	0.44	0.40	0.40	0.40	0.49	0.37	0.44	0.44	0.44	0.44	0.44	0.53	0.52	0.32
Suncor - Schuler Wind Energy Project	0.13	0.13	0.08	0.08	0.08	0.44	**0.33**	0.13	0.13	0.13	0.13	0.13	0.26	0.32	0.31

	Ardenville Wind (ARD1)*	Blue Trail Wind (BTR1)*	Castle River #1 (CR1)*	Castle Rock Wind Farm (CRR1)*	Cowley Ridge (CRWD)*	Enmax Taber (TAB1)*	Ghost Pine (NEP1)*	Kettles Hill (KHW1)*	McBride Lake Windfarm (AKE1)*	Soderglen Wind (GWW1)*	Summerview 1 (IEW1)*	Summerview 2 (IEW2)*	Suncor Chin Chute (SCR3)*	Suncor Magrath (SCR2)*	Suncor Wintering Hills (SCR4)*
Alberta Wind Energy Old Man River Wind Farm	0.53	0.53	0.61	0.61	0.61	0.30	0.15	0.53	0.53	0.53	0.53	0.53	0.51	0.45	0.17
Benign Energy Heritage Wind Farm	0.74	0.74	1.00	1.00	1.00	0.36	0.13	0.74	0.74	0.74	0.74	0.74	0.61	0.55	0.10
Benign Energy Heritage Wind Farm	0.74	0.74	1.00	1.00	1.00	0.36	0.13	0.74	0.74	0.74	0.74	0.74	0.61	0.55	0.10
ENEL Alberta HWY 785 Wind Farm	1.00	1.00	0.74	0.74	0.74	0.43	0.19	1.00	1.00	1.00	1.00	1.00	0.73	0.64	0.15
Enel Alberta Riverview Wind Farm	0.74	0.74	1.00	1.00	1.00	0.36	0.13	0.74	0.74	0.74	0.74	0.74	0.61	0.55	0.10
Windy Point Wind Farm	1.00	1.00	0.74	0.74	0.74	0.43	0.19	1.00	1.00	1.00	1.00	1.00	0.73	0.64	0.15
Vindt Willowridge Wind Farm	0.54	0.54	0.44	0.44	0.44	0.40	**0.31**	0.54	0.54	0.54	0.54	0.54	0.65	0.61	**0.34**
Renewable Energy Services Ltd PC006 Wind Farm	0.65	0.65	0.73	0.73	0.73	0.33	0.11	0.65	0.65	0.65	0.65	0.65	0.49	0.45	0.04
Geilectric Welsch Wind Farm 2	1.00	1.00	0.74	0.74	0.74	0.43	0.19	1.00	1.00	1.00	1.00	1.00	0.73	0.64	0.15
Fort Macleod Wind Aggregated Generating Facility	0.74	0.74	1.00	1.00	1.00	0.36	0.13	0.74	0.74	0.74	0.74	0.74	0.61	0.55	0.10
Blood Tribe Wild Turnip Hill Wind Project	0.69	0.69	0.59	0.59	0.59	0.53	0.31	0.69	0.69	0.69	0.69	0.69	0.90	0.84	0.22
Acciona New Dayton Wind Energy Project	0.64	0.64	0.55	0.55	0.55	0.54	0.32	0.64	0.64	0.64	0.64	0.64	0.81	1.00	0.28
Old Elm & Pothole Creek Wind Farm	0.61	0.61	0.55	0.55	0.55	0.42	0.28	0.61	0.61	0.61	0.61	0.61	0.63	0.67	0.23
Shear Wind Coyote Ridge Wind Project	0.64	0.64	0.55	0.55	0.55	0.54	0.32	0.64	0.64	0.64	0.64	0.64	0.81	1.00	0.28
Shear Wind Coyote Ridge Wind Project	0.64	0.64	0.55	0.55	0.55	0.54	0.32	0.64	0.64	0.64	0.64	0.64	0.81	1.00	0.28

b) Correlation of Planned Wind Capacity

	E.ON Vermillion River Wind Facility	E.ON Grizzly Bear Wind Facility	Wainwright Wind Project	BluEarth Bull Creek Wind Project	Suncor Hand Hills Wind Energy Project	Joss Wind Hand Hills Wind Project	Capital Power Halkirk Wind Project	GlenRidge Wind Farm Phase 1	Greengate Blackspring Ridge I Wind Project	Pteragen Peace Butte 116 MW Wind Farm	Naturener Wild Rose Wind Farm	Naturener Wild Rose Wind Farm Phase 2	Suncor - Schuler Wind Energy Project	Alberta Wind Energy Old Man River Wind Farm	Benign Energy Heritage Wind Farm	Benign Energy Heritage Wind Farm	ENEL Alberta HWY 785 Wind Farm	Enel Alberta Riverview Wind Farm	Windy Point Wind Farm	Vindt Willowridge Wind Farm	Renewable Energy Services Ltd PC006 Wind Farm	Geilectric Welsch Wind Farm 2	Fort Macleod Wind Aggregated Generating Facility	Blood Tribe Wild Turnip Hill Wind Project	Acciona New Dayton Wind Energy Project	Old Elm & Pothole Creek Wind Farm	Shear Wind Coyote Ridge Wind Project	Shear Wind Coyote Ridge Wind Project
E.ON Vermillion River Wind Facility	1.00																											
E.ON Grizzly Bear Wind Facility	1.00	1.00																										
Wainwright Wind Project	0.63	0.63	1.00																									
BluEarth Bull Creek Wind Project	0.70	0.70	0.72	1.00																								
Suncor Hand Hills Wind Energy Project	0.35	0.35	0.53	0.46	1.00																							
Joss Wind Hand Hills Wind Project	0.35	0.35	0.53	0.46	1.00	1.00																						
Capital Power Halkirk Wind Project	0.58	0.58	0.77	0.76	0.57	0.57	1.00																					
GlenRidge Wind Farm Phase 1	0.38	0.38	0.43	0.50	0.34	0.34	0.52	1.00																				
Greengate Blackspring Ridge I Wind Project	0.25	0.25	0.32	0.35	0.43	0.43	0.39	0.54	1.00																			
Pteragen Peace Butte 116 MW Wind Farm	0.31	0.31	0.36	0.42	0.35	0.35	0.44	0.64	0.63	1.00																		
Naturener Wild Rose Wind Farm	0.31	0.31	0.35	0.42	0.38	0.38	0.43	0.69	0.62	0.82	1.00																	
Naturener Wild Rose Wind Farm Phase 2	0.30	0.30	0.33	0.40	0.32	0.32	0.41	0.66	0.59	0.76	0.88	1.00																
Suncor - Schuler Wind Energy Project	0.29	0.29	0.38	0.39	0.31	0.31	0.41	0.45	0.35	0.47	0.44	0.37	1.00															
Alberta Wind Energy Old Man River Wind Farm	0.19	0.19	0.19	0.24	0.17	0.17	0.21	0.32	0.34	0.36	0.31	0.36	0.12	1.00														
Benign Energy Heritage Wind Farm	0.17	0.17	0.14	0.19	0.10	0.10	0.17	0.32	0.36	0.40	0.37	0.40	0.08	0.61	1.00													

Benign Energy Heritage Wind Farm	0.17	0.17	0.14	0.19	0.10	0.10	0.17	0.32	0.36	0.40	0.37	0.40	0.08	0.61	1.00	1.00												
ENEL Alberta HWY 785 Wind Farm	0.17	0.17	0.18	0.23	0.15	0.15	0.22	0.37	0.46	0.47	0.43	0.44	0.13	0.53	0.74	0.74	1.00											
Enel Alberta Riverview Wind Farm	0.17	0.17	0.14	0.19	0.10	0.10	0.17	0.32	0.36	0.40	0.37	0.40	0.08	0.61	1.00	1.00	0.74	1.00										
Windy Point Wind Farm	0.17	0.17	0.18	0.23	0.15	0.15	0.22	0.37	0.46	0.47	0.43	0.44	0.13	0.53	0.74	0.74	1.00	0.74	1.00									
Vindt Willowridge Wind Farm	0.21	0.21	0.26	0.29	0.34	0.34	0.30	0.40	0.60	0.47	0.47	0.46	0.22	0.40	0.44	0.44	0.54	0.44	0.54	1.00								
Renewable Energy Services Ltd PC006 Wind Farm	0.14	0.14	0.10	0.16	0.04	0.04	0.13	0.26	0.26	0.32	0.29	0.33	0.00	0.52	0.73	0.73	0.65	0.73	0.65	**0.33**	1.00							
Geilectric Welsch Wind Farm 2	0.17	0.17	0.18	0.23	0.15	0.15	0.22	0.37	0.46	0.47	0.43	0.44	0.13	0.53	0.74	0.74	1.00	0.74	1.00	0.54	0.65	1.00						
Fort Macleod Wind Aggregated Generating Facility	0.17	0.17	0.14	0.19	0.10	0.10	0.17	0.32	0.36	0.40	0.37	0.40	0.08	0.61	1.00	1.00	0.74	1.00	0.74	0.44	0.73	0.74	1.00					
Blood Tribe Wild Turnip Hill Wind Project	0.22	0.22	0.23	0.28	0.22	0.22	0.27	0.44	0.56	0.55	0.52	0.51	0.28	0.45	0.59	0.59	0.69	0.59	0.69	0.63	0.48	0.69	0.59	1.00				
Acciona New Dayton Wind Energy Project	0.25	0.25	0.29	0.33	0.28	0.28	0.33	0.46	0.57	0.56	0.53	0.52	0.32	0.45	0.55	0.55	0.64	0.55	0.64	0.61	0.45	0.64	0.55	0.84	1.00			
Old Elm & Pothole Creek Wind Farm	0.23	0.23	0.27	0.30	0.23	0.23	0.30	0.40	0.44	0.46	0.45	0.42	0.27	0.42	0.55	0.55	0.61	0.55	0.61	0.56	0.48	0.61	0.55	0.67	0.67	1.00		
Shear Wind Coyote Ridge Wind Project	0.25	0.25	0.29	0.33	0.28	0.28	0.33	0.46	0.57	0.56	0.53	0.52	0.32	0.45	0.55	0.55	0.64	0.55	0.64	0.61	0.45	0.64	0.55	0.84	1.00	0.67	1.00	
Shear Wind Coyote Ridge Wind Project	0.25	0.25	0.29	0.33	0.28	0.28	0.33	0.46	0.57	0.56	0.53	0.52	0.32	0.45	0.55	0.55	0.64	0.55	0.64	0.61	0.45	0.64	0.55	0.84	1.00	0.67	1.00	1.00

CORRELATION	1	0.7 - 0.99	0.35 - 0.69	0 - 0.34

Appendix L: Options for Long Term Wind Integration - Summary

Summarized from information provided in AESO Wind Integration Work Group Output Report (AESO, 2011 b). Blue font indicates additional information.

	Description	Price Visibility	Price Signal	Cost Method	Cost Allocation	Objectives Satisfied	Objectives Not Met	Major Concerns
Short Term 1100 to 1500 MW (ALL TO BE USED)								
Energy Market Merit Order (EMMO)	Dispatch the EMMO to balance supply and demand on the basis that the dispatches are expected to be required for energy rather than ramp rate.	Transparent	*Does not provide clear price signal to market on need for units that can provide fast ramp rate. Mixes price signal for energy with price signal for ramping service.*	Through Pool Price (and SMP)	To Load		Fairness, Efficiency	EMMO should not be used as a ramping service
Operating Reserves	Activate standby contingency reserves to manage risk of wind ramp down events when indicated by the wind forecast and/or system conditions. Direct available contingency reserves to produce energy in order to manage ramp rate requirements that are in excess of the EMMO capability. This will provide ramp rate to the system to manage wind ramp down events.	Transparent	*Specific price signal for development of flexible generation*	Through transmission tariff	To Load		Fairness	NWPP rules do not allow standby reserves to be used for non-contingency events and incremental reserves would need to be procured above mandatory volume during risk periods, increasing system costs
Wind Power Management	Utilize WPM to control wind ramp up events when the ramp requirement exceeds the ramp down capability of the EMMO.	Transparent		Pro rata basis across wind facilities ramping up and contributing the over generation condition.	To wind generator		Efficiency	Not a market solution WPM as contemplated results in very little lost generation, but the solution is not as robust when the total amount of wind capacity grows into the 2500 MW - 4000 MW range.

	Description	Price Visibility	Price Signal	Cost Method	Cost Allocation	Objectives Satisfied	Objectives Not Met	Major Concerns
Long Term (OPTIONS FOR STAKEHOLDER DISCUSSION)								
Energy Market Merit Order (EMMO)	Use EMMO as means of delivering a ramping service to the market.	Transparent	Does not provide clear price signal to market on need for units that can provide fast ramp rate. Mixes price signal for energy with price signal for ramping service.	Through Pool Price (and SMP) Spot market price will reflect both energy price and ramping costs associated with wind ramping events.	To Load		Operation impact of more frequent dispatches of short duration (fairness, efficiency); Reliability concerns with response times	Unclear energy market price signals for investment Bifurcated merit order ($0 and $999.99) due to generators unwilling to receive more frequent dispatches opting out of merit order. Since many units with fast ramping capability are higher in the merit order, dispatching these units through the EMMO for short periods results in price volatility.
Incremental Regulating Reserves	System balance through instantaneous coordinated dispatch (without lag associated with EMMO dispatch) without affecting SMP. Inherent ramping capability.	Transparent	Specific price signal for development of flexible generation	Procured as RR by AESO for benefit of entire market	To Load through transmission tariff		Efficiency (due to impact on energy price and accuracy of forecast in procuring reserves), fairness (benefit to wind generation at expense of load and other generators. Wind does not face same costs associated with supplying firm power through MOMC)	Purchased day-ahead (accuracy of wind forecast improves closer to real time) - value of an accurate wind power forecast near real-time would not be realized if IRR volumes used to manage variable generation are purchased day ahead Price impact associated with removing capacity from energy market RR price impact due to greater load following component added to product Allocating all costs of wind integration directly to load sends inappropriate investment signals and provides an advantage to wind generation Fewer market participants can participate Requires more units to be online and operating at partial load (less efficient)
Refinements to Short Term Plan	Develop a market solution or alternative to WPM and create a new AS that would be used instead of standby contingency reserves to replace los wind energy when required	Multiple - see above	Multiple - see above	Multiple - see above	Multiple - see above		Fairness, efficiency	*WPM is not a market based solution and is likely to grow as more capacity is added* *If reserves are used to manage wind, they will not be available for other contingencies (could use standby)* *WPM impacts GHG compliance?* *Using reserves has a market price impact*

	Description	Price Visibility	Price Signal	Cost Method	Cost Allocation	Objectives Satisfied	Objectives Not Met	Major Concerns
Ramping Service	Specific service to manage the reliability concerns created by wind ramp events allowing system ramp requirements to be met without over dispatching EMMO or purchasing IRR. Allows units with high ramp rates to be compensated outside the energy market price specifically for the provision of ramp rate in addition to energy and does not alter the SMP to dispatch units with high ramp rates.	Clear and transparent	Direct price signal for the value of a ramp rate in the market. (Does not alter SMP)	Dependent on market or ancillary service classification	If allocated on a causation basis within the existing market framework, wind generators would bear costs when the service was required to manage a ramping event. If classified as an AS, it would be paid by load and treat wind variability as equivalent to generation contingency events.*	Creates specific service to manage reliability concerns created by wind ramp events. Creates competitive outcome as more suppliers would be able to provide these services		Service would need to be more on a real-time basis than current ancillary services procured day ahead Ancillary or market service classification and how cost will be allocated Complexity *If wind generators are required to pay for their own needs then they are more likely to design more adequate or new solutions (or not enter the market). Having costs allocated to load when does not send the right incentives to improve the problem.
Wind Firming Service	The overall wind portfolio would be firmed centrally, removing uncertainty and variability associated with overall wind generation. Mimics a MOMC obligation for wind portfolio rather than individual generators. The service takes the place of the obligation to provide firm power. Aggregate generation experiences less variability		Sends a price signal on the cost of firming wind.	Wind generators fund a service that takes the place of providing firm power.	To wind generators	Reliability		Potentially removes capacity from the EMMO to supply the firming service Requires more capacity to firm than a market product (but is a market signal) Might not take advantage of the natural diversity of the wind portfolio.
Must Offer Must Comply	Wind generators would be obligated to enter an offer into the EMMO and comply with that offer, just as do other generators. Wind generators would be free to meet the obligation individually and the market would drive the most efficient outcome.*		Wind generation could be 'firmed' with a variety of options including dispatchable generation, demand response, storage devices and wind power management. This provides market based signals for the cheapest way to firm wind without the need to define a new service that may inadvertently favor one solution over another.	Varies by design but cost of managing variability would be managed by individual generators	Individual generators	Reliability (certainty of supply to system operator) Fairness (treats all forms of generation equivalently)		Not the most efficient outcome in terms of integrating the most wind with the least amount of capital investment (wind perspective) Flexibility inherent in market and diversity of wind may not be captured Joint offers may alleviate these two concerns Could create a barrier contrary to government policy Barrier to wind development If lack of wind is an acceptable operating reason not to deliver offered energy, there is no value to the system of the obligation however, no other generators are 100% firm

Appendix M: Relative Cost Calculations for Wind and No-Wind Scenarios

a) Cost of Capital

Capital Cost - SCGT	$1,150/kW
Capital Cost - CCGT	$1,435/kW
Capital Cost - Wind	$2,300/kW
Discount Rate	10%

Year	WIND Installed Capacity	Installed Capacity Required from Gas (20% of Wind)	CAPITAL COST - WIND		CAPITAL COST - SCGT		CAPITAL COST - CCGT	
	MW	MW	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE
2011	865	173	$1,989,500,000	**$1,989,500,000**	$198,950,000	**$198,950,000**	$248,255,000	**$248,255,000**
2017	1694	339	$3,896,200,000	**$2,199,303,326**	$389,620,000	**$219,930,333**	$486,178,000	**$274,434,806**
2022	2544	509	$5,851,200,000	**$2,050,809,905**	$585,120,000	**$205,080,990**	$730,128,000	**$255,905,410**
2032	3578	716	$8,229,400,000	**$1,112,043,520**	$822,940,000	**$111,204,352**	$1,026,886,000	**$138,763,691**

b) Fixed O&M

Fixed O&M - SCGT	$14,000/MW per year
Fixed O&M - CCGT	$15,500/MW per year
Fixed O&M - Wind	$50,000/MW per year
Discount Rate	10%

Year	WIND Installed Capacity	Installed Capacity Required from Gas (20% of Wind)	FIXED O&M COST - WIND		FIXED O&M COST - SCGT		FIXED O&M COST - CCGT	
	MW	MW	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE
2000	*38*	8	$1,900,000	**$5,420,922**	$106,400	**$303,572**	$117,800	**$336,097**
2001	*78*	16	$3,900,000	**$10,115,596**	$218,400	**$566,473**	$241,800	**$627,167**
2002	78	16	$3,900,000	**$9,195,996**	$218,400	**$514,976**	$241,800	**$570,152**
2003	153	31	$7,650,000	**$16,398,454**	$428,400	**$918,313**	$474,300	**$1,016,704**

2004	251	50	$12,550,000	**$24,456,400**	$702,800	**$1,369,558**	$778,100	**$1,516,297**
2005	251	50	$12,550,000	**$22,233,091**	$702,800	**$1,245,053**	$778,100	**$1,378,452**
2006	362	72	$18,100,000	**$29,150,231**	$1,013,600	**$1,632,413**	$1,122,200	**$1,807,314**
2007	497	99	$24,850,000	**$36,382,885**	$1,391,600	**$2,037,442**	$1,540,700	**$2,255,739**
2008	497	99	$24,850,000	**$33,075,350**	$1,391,600	**$1,852,220**	$1,540,700	**$2,050,672**
2009	563	113	$28,150,000	**$34,061,500**	$1,576,400	**$1,907,444**	$1,745,300	**$2,111,813**
2010	777	155	$38,850,000	**$42,735,000**	$2,175,600	**$2,393,160**	$2,408,700	**$2,649,570**
2011	865	173	$43,250,000	**$43,250,000**	$2,422,000	**$2,422,000**	$2,681,500	**$2,681,500**
2012	1003	201	$50,158,333	**$45,598,485**	$2,808,867	**$2,553,515**	$3,109,817	**$2,827,106**
2013	1141	228	$57,066,667	**$47,162,534**	$3,195,733	**$2,641,102**	$3,538,133	**$2,924,077**
2014	1280	256	$63,975,000	**$48,065,364**	$3,582,600	**$2,691,660**	$3,966,450	**$2,980,053**
2015	1418	284	$70,883,333	**$48,414,270**	$3,969,467	**$2,711,199**	$4,394,767	**$3,001,685**
2016	1556	311	$77,791,667	**$48,302,505**	$4,356,333	**$2,704,940**	$4,823,083	**$2,994,755**
2017	1694	339	$84,700,000	**$47,810,942**	$4,743,200	**$2,677,413**	$5,251,400	**$2,964,278**
2018	1864	373	$93,200,000	**$47,826,337**	$5,219,200	**$2,678,275**	$5,778,400	**$2,965,233**
2019	2034	407	$101,700,000	**$47,443,801**	$5,695,200	**$2,656,853**	$6,305,400	**$2,941,516**
2020	2204	441	$110,200,000	**$46,735,558**	$6,171,200	**$2,617,191**	$6,832,400	**$2,897,605**
2021	2374	475	$118,700,000	**$45,763,988**	$6,647,200	**$2,562,783**	$7,359,400	**$2,837,367**
2022	2544	509	$127,200,000	**$44,582,824**	$7,123,200	**$2,496,638**	$7,886,400	**$2,764,135**
2023	2647.4	529	$132,370,000	**$42,177,161**	$7,412,720	**$2,361,921**	$8,206,940	**$2,614,984**
2024	2750.8	550	$137,540,000	**$39,840,439**	$7,702,240	**$2,231,065**	$8,527,480	**$2,470,107**
2025	2854.2	571	$142,710,000	**$37,580,003**	$7,991,760	**$2,104,480**	$8,848,020	**$2,329,960**
2026	2957.6	592	$147,880,000	**$35,401,296**	$8,281,280	**$1,982,473**	$9,168,560	**$2,194,880**
2027	3061	612	$153,050,000	**$33,308,139**	$8,570,800	**$1,865,256**	$9,489,100	**$2,065,105**
2028	3164.4	633	$158,220,000	**$31,302,984**	$8,860,320	**$1,752,967**	$9,809,640	**$1,940,785**
2029	3267.8	654	$163,390,000	**$29,387,128**	$9,149,840	**$1,645,679**	$10,130,180	**$1,822,002**
2030	3371.2	674	$168,560,000	**$27,560,907**	$9,439,360	**$1,543,411**	$10,450,720	**$1,708,776**
2031	3474.6	695	$173,730,000	**$25,823,857**	$9,728,880	**$1,446,136**	$10,771,260	**$1,601,079**
2032	3578	716	$178,900,000	**$24,174,859**	$10,018,400	**$1,353,792**	$11,091,800	**$1,498,841**

c) Cost of Energy Supplied – Variable O&M

Variable O&M - SCGT	$54.20/MWh (including $0.90/tonne of emissions)
Variable O&M - CCGT	$41.37/MWh (including $0.67/tonne of emissions)
Variable O&M - Wind	$2.00/MWh
Wind Capacity Factor	35%
Discount Rate	10%

Year	WIND Installed Capacity	Wind Generation	VARIABLE O&M COST - WIND		VARIABLE O&M COST - SCGT		VARIABLE O&M COST - CCGT	
	MW	MWh	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE	REAL 2011$	PRESENT VALUE
2000	*38*	116508	$233,016	**$664,822**	$6,314,734	**$18,016,672**	$4,819,936	**$13,751,840**
2001	*78*	239148	$478,296	**$1,240,577**	$12,961,822	**$33,619,627**	$9,893,553	**$25,661,328**
2002	78	239148	$478,296	**$1,127,797**	$12,961,822	**$30,563,297**	$9,893,553	**$23,328,480**
2003	153	469098	$938,196	**$2,011,106**	$25,425,112	**$54,500,985**	$19,406,584	**$41,599,737**
2004	251	769566	$1,539,132	**$2,999,333**	$41,710,477	**$81,281,920**	$31,836,945	**$62,041,200**
2005	251	769566	$1,539,132	**$2,726,666**	$41,710,477	**$73,892,655**	$31,836,945	**$56,401,091**
2006	362	1109892	$2,219,784	**$3,574,984**	$60,156,146	**$96,882,075**	$45,916,232	**$73,948,551**
2007	497	1523802	$3,047,604	**$4,461,997**	$82,590,068	**$120,920,119**	$63,039,689	**$92,296,408**
2008	497	1523802	$3,047,604	**$4,056,361**	$82,590,068	**$109,927,381**	$63,039,689	**$83,905,826**
2009	563	1726158	$3,452,316	**$4,177,302**	$93,557,764	**$113,204,894**	$71,411,156	**$86,407,499**
2010	777	2382282	$4,764,564	**$5,241,020**	$129,119,684	**$142,031,653**	$98,555,006	**$108,410,507**
2011	865	2652090	$5,304,180	**$5,304,180**	$143,743,278	**$143,743,278**	$109,716,963	**$109,716,963**
2012	1003	3075709	$6,151,418	**$5,592,198**	$166,703,428	**$151,548,571**	$127,242,081	**$115,674,619**
2013	1141	3499328	$6,998,656	**$5,784,013**	$189,663,578	**$156,746,758**	$144,767,199	**$119,642,314**
2014	1280	3922947	$7,845,894	**$5,894,736**	$212,623,727	**$159,747,353**	$162,292,317	**$121,932,620**
2015	1418	4346566	$8,693,132	**$5,937,526**	$235,583,877	**$160,906,958**	$179,817,435	**$122,817,728**
2016	1556	4770185	$9,540,370	**$5,923,819**	$258,544,027	**$160,535,499**	$197,342,553	**$122,534,199**
2017	1694	5193804	$10,387,608	**$5,863,534**	$281,504,177	**$158,901,769**	$214,867,671	**$121,287,199**
2018	1864	5715024	$11,430,048	**$5,865,422**	$309,754,301	**$158,952,934**	$236,430,543	**$121,326,252**
2019	2034	6236244	$12,472,488	**$5,818,508**	$338,004,425	**$157,681,559**	$257,993,414	**$120,355,832**
2020	2204	6757464	$13,514,928	**$5,731,649**	$366,254,549	**$155,327,682**	$279,556,286	**$118,559,155**
2021	2374	7278684	$14,557,368	**$5,612,496**	$394,504,673	**$152,098,629**	$301,119,157	**$116,094,470**
2022	2544	7799904	$15,599,808	**$5,467,638**	$422,754,797	**$148,172,977**	$322,682,028	**$113,098,082**
2023	2647.4	8116928	$16,233,857	**$5,172,607**	$439,937,519	**$140,177,652**	$335,797,328	**$106,995,377**
2024	2750.8	8433953	$16,867,906	**$4,886,031**	$457,120,242	**$132,411,451**	$348,912,627	**$101,067,560**
2025	2854.2	8750977	$17,501,954	**$4,608,812**	$474,302,964	**$124,898,794**	$362,027,927	**$95,333,268**
2026	2957.6	9068002	$18,136,003	**$4,341,615**	$491,485,687	**$117,657,766**	$375,143,226	**$89,806,306**
2027	3061	9385026	$18,770,052	**$4,084,910**	$508,668,409	**$110,701,066**	$388,258,526	**$84,496,367**
2028	3164.4	9702050	$19,404,101	**$3,838,998**	$525,851,132	**$104,036,843**	$401,373,825	**$79,409,672**
2029	3267.8	10019075	$20,038,150	**$3,604,037**	$543,033,854	**$97,669,412**	$414,489,124	**$74,549,512**
2030	3371.2	10336099	$20,672,198	**$3,380,070**	$560,216,577	**$91,599,887**	$427,604,424	**$69,916,740**
2031	3474.6	10653124	$21,306,247	**$3,167,038**	$577,399,299	**$85,826,727**	$440,719,723	**$65,510,179**
2032	3578	10970148	$21,940,296	**$2,964,805**	$594,582,022	**$80,346,208**	$453,835,023	**$61,326,986**

Appendix N: Levelized Cost of Energy – Results

Base case scenarios used throughout the analysis are identified in bold font. Inputs not identified in Appendix N as variable are identified in Tables 13 and 14.

a) Wind

Capacity Factor	Variable Fuel ($/MWh)	Capital Costs ($/kW - 2011)	Fixed O&M ($/kWy)	RESULT ($/MWh)
41%	$0.00	$2,530.00	$55.00	$84.41
	$0.00	$2,300.00	$50.00	$76.91
	$0.00	$2,070.00	$45.00	$69.41
37%	$0.00	$2,530.00	$55.00	$93.33
	$0.00	$2,300.00	$50.00	$85.02
	$0.00	$2,070.00	$45.00	$76.70
35%	$0.00	$2,530.00	$55.00	$98.55
	$0.00	**$2,300.00**	**$50.00**	**$89.77**
	$0.00	$2,070.00	$45.00	$80.98
30%	$0.00	$2,530.00	$55.00	$114.66
	$0.00	$2,300.00	$50.00	$104.41
	$0.00	$2,070.00	$45.00	$94.16
27%	$0.00	$2,530.00	$55.00	$127.19
	$0.00	$2,300.00	$50.00	$115.80
	$0.00	$2,070.00	$45.00	$104.41

b) Simple Cycle Gas Turbine

Capacity Factor	Variable Fuel ($/MWh)	Capital Costs ($/kW - 2011)	Fixed O&M ($/kWy)	RESULT ($/MWh)
30%	$78.40	$1,265.00	$15.40	$137.69
		$1,150.00	$14.00	$132.37
		$1,035.00	$12.60	$127.05
	$49.00	$1,265.00	$15.40	$109.86
		$1,150.00	**$14.00**	**$104.54**
		$1,035.00	$12.60	$99.21
	$34.30	$1,265.00	$15.40	$95.94
		$1,150.00	$14.00	$90.62
		$1,035.00	$12.60	$85.30
24%	$78.40	$1,265.00	$15.40	$152.33
		$1,150.00	$14.00	$145.67
		$1,035.00	$12.60	$139.02

	$49.00	$1,265.00	$15.40	$124.49
		$1,150.00	$14.00	$117.84
		$1,035.00	$12.60	$111.19
	$34.30	$1,265.00	$15.40	$110.58
		$1,150.00	$14.00	$103.92
		$1,035.00	$12.60	$97.27
13%	$78.40	$1,265.00	$15.40	$214.25
		$1,150.00	$14.00	$201.97
		$1,035.00	$12.60	$189.69
	$49.00	$1,265.00	$15.40	$186.42
		$1,150.00	$14.00	$174.13
		$1,035.00	$12.60	$161.85
	$34.30	$1,265.00	$15.40	$172.50
		$1,150.00	$14.00	$160.22
		$1,035.00	$12.60	$147.94

c) Combined Cycle Gas Turbine (300 MW)

Capacity Factors for CCGT based on the following assumptions:

MW	% of CAP	Capacity Factor		
30	10%	**60%**	**50%**	**40%**
150	50%	**75%**	**65%**	**60%**
120	40%	80%	75%	70%
300	*100%*	75.5%	67.5%	62.0%

Capacity Factor	Variable Fuel ($/MWh)	Capital Costs ($/kW - 2011)	Fixed O&M ($/kWy)	RESULTS
75.5%	$59.20	$1,578.50	$17.05	$91.05
		$1,435.00	$15.50	$88.44
		$1,291.50	$13.95	$85.51
	$37.00	$1,578.50	$17.05	$69.31
		$1,435.00	$15.50	$66.69
		$1,291.50	$13.95	$64.07
	$25.90	$1,578.50	$17.05	$58.43
		$1,435.00	$15.50	$55.82
		$1,291.50	$13.95	$53.19
67.5%	$59.20	$1,578.50	$17.05	$94.47
		$1,435.00	$15.50	$91.54

		$1,291.50	$13.95	$88.60
	$37.00	$1,578.50	$17.05	$72.72
		$1,435.00	**$15.50**	**$69.79**
		$1,291.50	$13.95	$66.87
	$25.90	$1,578.50	$17.05	$61.65
		$1,435.00	$15.50	$58.92
		$1,291.50	$13.95	$55.98
62%	$59.20	$1,578.50	$17.05	$97.32
		$1,435.00	$15.50	$94.14
		$1,291.50	$13.95	$90.94
	$37.00	$1,578.50	$17.05	$75.57
		$1,435.00	$15.50	$72.39
		$1,291.50	$13.95	$69.20
	$25.90	$1,578.50	$17.05	$64.70
		$1,435.00	$15.50	$61.52
		$1,291.50	$13.95	$58.32

Appendix O: Emissions Output and Prices/Costs

a) Emissions Price applied to all Gas-Fired Generation in Section 5 (above limit of 100,000 tonnes per year) except SCGT at 13% Capacity Factor, as per the following:

Emissions Output					
	Plant Size (MW)	Emissions Intensity (tonnes/MWh)	Max Tonnes/Yr	Capacity Factor	Tonnes /Yr at Capacity Factor
CCGT	300	0.37	972360	75.5%	734132
				67.5%	656343
				62%	602863
SCGT	100	0.5	438000	30%	131400
				24%	105120
				13%	56940

b) Increases in carbon prices against base case applied to Gas-Fired Generation in Section 6.2, Table 19 were calculated as follows:

Carbon Price SGER					
INITIAL: $15/tonne x 12% = $1.80/tonne		Initial Price ($/tonne)	Added Cost ($/tonne)	Emissions Intensity (tonne/MWh)	Additional Cost ($/MWh)
$30/tonne x12% = $3.60/tonne	CCGT	$1.80	$1.80	$0.37	$0.67
$45/tonne x 12% = $5.40/tonne		$1.80	$3.60	$0.37	$1.33
$60/tonne x 12% = 7.20/tonne		$1.80	$5.40	$0.37	$2.00
$30/tonne x12% = $3.60/tonne	SCGT	$1.80	$1.80	$0.50	$0.90
$45/tonne x 12% = $5.40/tonne		$1.80	$3.60	$0.50	$1.80
$60/tonne x 12% = 7.20/tonne		$1.80	$5.40	$0.50	$2.70

c) Offset credits and costs to gas-fired generation in Section 6.2, Table 19 were calculated as follows:

Offset Credit = $14/tonne				
	"Tonnes/Yr at Capacity Factor" x $14/tonne ($/yr)	12% of Column 2 ($/yr)	Generation based on Plant Size and Capacity Factor (MWh)	Additional Cost ($/MWh)
CCGT	$9,188,802.00	$1,102,656.24	1773900	$0.62
SCGT	$1,839,600.00	$220,752.00	262800	$0.84

d) Carbon tax costs to gas-fired generation in Section 6.2, Table 20 were calculated as follows:

Carbon Tax on 100% Emissions			
	Carbon Price ($/tonne)	Emissions Intensity (tonne/MWh)	Additional Cost ($/MWh)
CCGT	$15/tonne	0.37	$5.55
	$30/tonne		$11.10
SCGT	$15/tonne	0.5	$7.50
	$30/tonne		$15.00

Appendix P: WPPI and ecoEnergy Subsidy Expenses

Year	Total Wind Gen (MWh)	Federal Subsidy (In Year's $)	Federal Subsidy in 2011$
2003	132,571.83	$1,325,718.30	$1,550,547.72
2004	334,755.26	$3,347,552.61	$3,825,774.41
2005	535,985.99	$5,359,859.89	$6,005,445.25
2006	657,756.96	$6,577,569.59	$7,201,718.53
2007	1,188,388.57	$11,883,885.66	$12,732,734.64
2008	1,308,659.36	$13,086,593.59	$13,561,236.88
2009	1,304,170.27	$13,041,702.67	$13,644,327.12
2010	1,394,827.15	$13,948,271.53	$14,330,415.96
2011	2,129,116.44	$21,291,164.44	$21,291,164.44
2012*	1,225,245.31	$12,252,453.06	$12,101,188.21
			$106,244,553.16

*2012 data is to July 31, 2012 and does not include Caste Rock Wind Farm

Appendix Q: Sample LCOE Calculation – Wind Base Case Scenario

a) LCOE Inputs for Wind Base Case Scenario

Heat Rate (GJ/MWh)	0
Facility Life	25
Capacity Factor	35%
Net Nameplate	100
Discount Rate	10%
Capital Cost ($/kW - 2011)	$2,300
Tax Rate	25%
Depreciation	50%

		Escalator
Fixed O&M $/MW-year	$50,000	0%
Variable O&M $/MWh	$2.00	0%
Fuel Price / GJ	$0.00	0%

LCOE = Total Life Cycle Cost/LEC Denominator, where

Total Life Cycle Cost (Present Value) = [Investment – (Tax Rate x PVDEP) + (1-Tax Rate)*PVOM]/(1-Tax Rate)

LEC Denominator = Total Life Cycle Facility Output (Present Value)

PVDEP = Present Value of Depreciation

PVOM = Present Value of O&M

c) Wind Base Case Scenario Example

Year	LEC Denominator (MWh)	Investment Expenditure	TOM = FOM + VOM	FOM	VOM	Fuel (Marginal VarCost)	Facility Output (MWh)	PVDEP	PVOM	DEP	INV - DEP
2011	306,600	$230,000,000	$5,613,200	$5,000,000	$613,200	$0	306,600	$115,000,000	$5,613,200	$115,000,000	$115,000,000
2012	278,727	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$52,272,727	$5,102,909	$57,500,000	$57,500,000
2013	253,388	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$23,760,331	$4,639,008	$28,750,000	$28,750,000
2014	230,353	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$10,800,150	$4,217,280	$14,375,000	$14,375,000
2015	209,412	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$4,909,159	$3,833,891	$7,187,500	$7,187,500
2016	190,374	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$2,231,436	$3,485,356	$3,593,750	$3,593,750
2017	173,068	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$1,014,289	$3,168,505	$1,796,875	$1,796,875
2018	157,334	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$461,040	$2,880,459	$898,438	$898,438
2019	143,031	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$209,564	$2,618,599	$449,219	$449,219
2020	130,028	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$95,256	$2,380,545	$224,609	$224,609
2021	118,208	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$43,298	$2,164,132	$112,305	$112,305
2022	107,461	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$19,681	$1,967,392	$56,152	$56,152
2023	97,692	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$8,946	$1,788,539	$28,076	$28,076
2024	88,811	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$4,066	$1,625,944	$14,038	$14,038
2025	80,737	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$1,848	$1,478,131	$7,019	$7,019
2026	73,398	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$840	$1,343,755	$3,510	$3,510
2027	66,725	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$382	$1,221,596	$1,755	$1,755
2028	60,659	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$174	$1,110,542	$877	$877
2029	55,145	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$79	$1,009,583	$439	$439
2030	50,132	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$36	$917,803	$219	$219
2031	45,574	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$16	$834,366	$110	$110
2032	41,431	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$7	$758,515	$55	$55
2033	37,665	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$3	$689,559	$27	$27
2034	34,241	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$2	$626,872	$14	$14
2035	31,128	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$1	$569,883	$7	$7
2036	28,298	0	$5,613,200	$5,000,000	$613,200	$0	306,600	$0	$518,076	$3	$3
							Total	**$210,833,333**	**$56,564,441**		
							TLCC =	**$292,953,330**	**LCOE =**	**$89.77**	

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