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The Economics of Wind Power with Energy Storage

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The Economics of Wind Power with Energy Storage

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Abstract

We develop a nonlinear mathematical optimization program for investigating the economic and environmental implications of wind penetration in electrical grids and evaluating how hydropower storage could be used to offset wind power intermittence. When wind power is added to an electrical grid consisting of thermal and hydropower plants, it increases system variability and results in a need for additional peak-load, gas-fired generators. Our empirical application using load data for Alberta's electrical grid shows that 32% wind penetration (normalized to peak demand) results in a net cost increase of \$C5.20/ MWh, while 64% wind penetration could result in an increase of \$12.50/MWh. Costs of reducing CO_2 emissions are estimated to be \$41-\$56 per t CO_2 . When pumped hydro storage is introduced in the system or the capacity of the water reservoirs is enhanced, the hydropower facility could provide most of the peak load requirements obviating the need to build large peak-load gas generators.

Keywords: Renewable energy, carbon costs, hydropower storage, mathematical programming

JEL codes: Q40, Q42, Q50

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1 Introduction

Concern about climate change and rising concentrations of CO_2 in the atmosphere has increased the search for alternative energy resources with lower CO_2 emissions. One approach is to switch from fuels with high carbon content per unit of energy, such as coal and oil, to ones with lower carbon content such as natural gas, but there are limits to such substitutions because there are limits to the availability of cleaner fossil fuels (Banks, 2003). One alternative, therefore, is to shift away from fossil fuels to renewable energy resources. Of renewable options, wind power is often considered the 'best'.

Wind energy has become the world's fastest growing energy resource, partly because of advances in technology and its reputation as a cost-effective renewable energy resource. According to the World Wind Energy Association, during the last five years wind energy capacity more than tripled, from 13,700 MW in 1999 to 47,600 MW in 2004 (WWEA, 2005). The most successful wind energy markets have been in Europe, particularly Denmark, Germany and Spain; EU policy is to increase installed renewable energy capacity, meaning primarily wind, to 15% of total electrical generating capacity within the next decade (ESB National Grid, 2004). In Denmark, the current average penetration rate of wind-produced energy is more than 20%. In some areas of western Denmark, wind accounts for as much as 50% of electrical power generation, and the Danish government's target is for wind to account for half of all power generated in the country by 2030 (Pitt et al., 2005). Although Europe accounts for 70% of the world's installed wind power generation capacity, there is now an upsurge in wind use in the United States and Canada, as well as in many developing countries. With improvements in technology and growth in the market for wind power, the cost of electricity generated by modern wind farms has declined by some 80% since 1980 – from about 38 cents per kilowatt hour (KWh) to about 4 cents. Engineers claim that costs will continue to decline so that, with increasing oil prices, wind power will be competitive with fossil fuel energy (DeCarolis and Keith, 2006).

Most cost estimates of wind power ignore the externality costs that wind imposes on an electrical grid – the costs of maintaining idle capacity and spinning reserves in thermal power plants in the event that wind is unavailable for generating electricity. Non-wind power generators need to be able to provide electricity the moment the power from wind is unavailable. If backup power is provided by a coal-fired generator, for example, it needs to be running continuously (perhaps at part capacity), burning fuel but not delivering power to the grid. Fuel efficiency may even be reduced, at least in the short run, because thermal generators function below their optimal operating range, leading to even higher costs and greater CO_2 emissions than otherwise. If backup power is provided by a peak-load generator, such as an open-cycle gas turbine or diesel plant, more frequent stops and starts brought about by vagaries in wind power add to overall operating costs. Peak-load generators also tend to be inefficient (typically below 30%), which leads to higher fuel consumption and CO_2 emissions compared to base-load generators. Finally, wind-generated power may be available when it is not needed, and must be stored, sold into another grid (if available), or wasted.

A number of researchers have proposed energy storage for offsetting wind intermittence (Belanger and Gagnon, 2002; Korpaas et al., 2003; Castronuovo and Lopes, 2004). A storage system generally imposes an energy penalty during both the input and output conversion processes. A typical battery system has a roundtrip efficiency of about 80%, while the efficiency of a regenerative fuel cell system is about 35% to 40%. As a substantial fraction of the energy is wasted in such storage systems, the capacity of a wind farm needs to be increased to overcome these losses (Love et al., 2003). A better storage alternative is hydraulics. Since hydroelectric power plants can be used (and are used in some systems) to supply peak-load power, they are an ideal means for storing wind-generated energy and providing power when wind is unavailable. Using wind forecasts, hydropower plants can adjust their storage and discharges so that they provide energy to the system almost instantaneously, operating much like a peak-load plant.

Where hydropower is available, it constitutes an ideal storage device in some ways as power can be made available at any time, including peak times. A traditional hydropower plant can be enhanced by pumped hydro storage. In a pumped hydro storage system, a second reservoir located below the first is required. When there is surplus energy in the grid (i.e., when wind power is available to such an extent that it displaces coal and/or gas-fired capacity already on line), water is pumped from the lower reservoir into the upper reservoir where it is stored (Schoenung et al., 1996). When electricity is in short supply because there is insufficient wind and/or at peak times, water is released to generate power.

A number of researchers have investigated the impact of wind penetration in electricity grids from a purely practical (engineering) standpoint (Belanger and Gagnon, 2002; Love et al., 2003; Lund, 2005; Weisser and Garcia, 2005), but only a few have done it from an economics perspective (Liik et al., 2003; DeCarolis and Keith, 2006). For instance, while Lund (2005) used an input-output model for evaluating large-scale wind integration in Denmark, he does not provide least-cost alternatives for adapting the generating capacity of thermal power plants to wind variability. Our interest in this paper is to assess the overall economic impact of introducing wind power into electrical grids and evaluate the trade-offs from increasing levels of wind penetration, as well as the costs of reducing CO_2 emissions. Thus, we construct a nonlinear constrained optimization program of an electrical grid that accounts for fossil-fuel power plants, wind power, hydropower and pumped storage, and searches for the best possible allocation of energy across generators and the optimum management of reservoir volumes and water flows within the pumped storage system.

The nonlinear constrained optimization model of an electrical grid is described in the next section. The model is used to provide a better understanding of the interrelations among major power generating sources and energy storage capacities, evaluate multiple scenarios with increasing levels of wind penetration, and determine how different power plants need to adjust their operations to offset variability in the availability of wind power. This approach leads to estimates of the marginal values (shadow prices) of unexpected changes in wind and the marginal costs of reducing CO_2 emissions. To illustrate the capabilities of the model we use the Alberta electrical grid as a case study, but only in the special case where existing thermal generation capacity is displaced by wind to reduce carbon dioxide emissions. We leave to further research the situation of adding wind to a system that needs new capacity to meet load growth. The Alberta grid and data are discussed in section 3, while model results are provided in section 4. Our conclusions follow.

2 Integrating Wind Power and Hydro Storage: A Constrained Optimization Approach

In this section, a mathematical programming model of an electrical grid is developed to assign electrical generation among generators/power plants in a way that minimizes total generation costs. The electrical grid operator is assumed to be completely rational in the sense that she is perfectly informed about generation costs and capacities, technical constraints, available wind-generated power, river flows and future demand for electricity. Mathematically, the objective is to assign generation of power across *N* available power generators (which are coal or gas fired, wind or hydro turbines) over T periods (hours) so as to minimize total generation costs:

$$\underset{Q_{t,i},O_t,R_t}{\text{Minimize}}\ TC = \sum_{i=1}^{N}\left(F_i \times C_i + \sum_{t=1}^{T}\left(pf_i \times E_{t,i} + c_i \times Q_{t,i}\right)\right), \tag{1}$$

where TC is total cost ($); F_i is the fixed cost ($) and C_i the nameplate capacity of generator i; pf_i is the price of fuel ($/GJ) used by generator i and $E_{i,t}$ is the fuel consumption (GJ) of generator i at time t, which depends on the quantity of electricity delivered; c_i refers to the non-fuel variable (or operating and maintenance, O&M) costs of generator i ($/MWh) and $Q_{t,i}$ is the electricity output (MW) delivered by generator (power plant) i at time t; and the time step is hourly. In addition to deciding how much output to produce from each electrical generator, the system operator also needs to control the outflow of water O_t from behind a hydro dam and the flow of water R_t pumped from the lower reservoir back into the upper reservoir for storage.

The cost function is minimized subject to a number of constraints and auxiliary equations that are derived from the need to satisfy demand for electricity in each period and the specific characteristics of each power plant.

· *Capacity.* The energy produced by each generator/power plant in each period should not exceed its nameplate capacity:

$$Q_{t,i} \le C_i, \quad \forall t = 1,...,T, \quad \forall i = 1,...,N\,. \tag{2}$$

· *Fossil-fuel plants.*

Fuel consumption is related to electricity output as follows:

$$E_{i,t} = \frac{Q_{t,i}}{0.278 \times \eta_i}, \tag{3}$$

where η_i is the fuel efficiency parameter of generator i and the factor 0.278 is used to convert

MWh into GJ. Since coal and gas power plants cannot ramp up or ramp down instantaneously, the following constraints are required:

Ramping up: $Q_{t,i} - Q_{t-1,i} \leq MU_i$, $\forall\, i = 1, \ldots, Nff$ (4)

Ramping down: $Q_{t,i} - Q_{t-1,i} \geq MD_i$, $\forall\, i = 1, \ldots, Nff$ (5)

MU_i is the maximum amount by which generator *i*'s electrical power output (MW) can be increased in a single period, MD_i is the maximum amount by which it can be decreased, and there are *Nff* fossil fuel generators.

· *Wind power.* We account for wind availability by adding the following inequality constraint:

$$Q_{t,wind} \leq W_t, \qquad \forall t = 1,\ldots, T, \tag{6}$$

where W_t is the power aggregated across all existing wind farms. Equation (6) indicates that the wind power available to the grid cannot exceed that generated by the various wind farms. As discussed below, a wind power series can be developed from available data on wind speconeds, although a wind speed time series could be generated by random sampling from a Weibul distribution or using more comprehensive time series models (e.g., see Milligan et al., 2003).

· *Hydropower.* The power released from a hydropower plant depends on the hydraulic head, the water discharge and a set of constants:

$$Q_{t,hydro} = \eta_h \times g \times d \times O_t \times H_t \times 10^{-6}, \tag{7}$$

where η_h (*h* refers to a hydropower generator) is the turbine overall efficiency parameter, *g* is acceleration of gravity (m/s^2), *d* is the density of water (kg/m^3), O_t is the average water discharge that goes through the turbine during period *t* (m^3/s), H_t is the hydraulic head (height in m between the water level and turbine), and the factor 10^{-6} is used for converting Watts (kg m^2/s^3) to MW units.

Water is stored in an upper reservoir so that the hydropower operator can regulate the discharge at his convenience. In a similar fashion, water is stored in a lower reservoir and the hydropower operator can regulate the pumped flow of water to be recycled back into the upper reservoir. The difference between the water that enters the upper reservoir and the discharge equals the rate of change of the upper reservoir's volume:

$$I_t + R_t - O_t = V_t^U - V_{t-1}^U, \tag{8}$$

where I denotes the inflow, O is outflow, R is the flow of water pumped from the lower (denoted L) to upper (U) reservoirs, and V_t^U is the flow of water in the upper reservoir at time t. The hydraulic head depends on the storage volume in the upper reservoir as follows:

$$H_t = H^{min} + V_t^U / A, \tag{9}$$

where H^{min} is the minimum head at which the hydropower facility could operate and A is the surface area of the upper or main reservoir. The hydropower plant is designed for a maximum discharge O^{max} and a maximum pumped flow R^{max}, and the upper and lower reservoirs have maximum storage volumes of $V_t^{U\_Max}$ and $V_t^{L\_Max}$, respectively.

$$0 \le O_t \le O^{max}, \ \forall t = 1, ..., T \tag{10}$$

$$0 \le R_t \le R^{max}, \ \forall t = 1, ..., T \tag{11}$$

$$0 \le V_t^U \le V_t^{U\_Max}, \ \forall t = 1, ..., T \tag{12}$$

$$0 \le V_t^L \le V_t^{L\_Max}, \ \forall t = 1, ..., T \tag{13}$$

The nameplate capacity for the hydropower plant is determined by the maximum outflow and the highest water level:

$$C_{hydro} = \eta_h \times g \times d \times O^{\max}\left(H^{\min} + \frac{V^{\max}}{A}\right)\times 10^{-6}. \quad (14)$$

Finally, the energy consumption for the pumped storage system is,

$$S_t = 1/\eta_s \times g \times d \times R_t \times H_t \times 10^{-6}, \quad (15)$$

where η_s is the efficiency of the pumped storage system.[1]

· *Demand*. The system must satisfy demand for electricity in each period (D_t) plus the energy required to pump water into storage in each period:

$$\sum_{i=1}^{N} Q_{t,i} \geq D_t + S_t,\ \forall t = 1, ..., T \quad (16)$$

· *Greenhouse gas emissions*. Finally, the model estimates CO_2 emissions for each of the power generators factors as follows:

$$CO2_t = \sum_{i=1}^{Nff} E_{t,i} \times \xi_i,\ \forall\ \ i = 1, \ldots, Nff, \quad (17)$$

where $E_{i,t}$ is fuel consumption measured in GJ, and ξ_i is the emission factor for generator i, measured in t CO_2 per GJ.

3 Empirical Application: Increased Wind Penetration in Alberta

Interest in wind power as a promising source of electricity has grown significantly over the past few years. Canada's Wind Power Production Incentive (WPPI), announced in the December 2001 budget, was intended to encourage electric utilities, independent power producers and other stakeholders to gain experience with this emerging and promising energy

[1] We assume that the water level of the lower reservoir is always at the turbine discharge, and thus that its variation in height is negligible.

source. Subsequently, wind energy became a mainstay of the federal government's plan to meet its Kyoto obligations (Government of Canada, 2005), with \$200 million of direct federal subsidies for wind power generation and upwards of \$300 million in tax incentives (for all renewables) to be made available in the period up to 2010. The objective is to increase installed wind generating capacity to 4000 MW by Kyoto's commitment period, up from only 214 MW of installed capacity in 2001. The Alberta Electric System Operator (AESO) has received applications from independent power suppliers to connect approximately 600 MW of wind generation capacity in addition to 200 MW of capacity in projects already approved. In addition, there have been inquires from interested parties regarding the potential installation of 1000 to 1500 MW of additional capacity (ABB, 2004). These capacity requirements are significant compared with a peak hourly demand of 8230 MW in 2003. If such investments come to fruition, there could be adverse economic impacts on existing power generators because of the intermittency of wind power.

Alberta currently relies primarily on fossil fuels for electric power, with 48% of installed generating capacity based on coal and 41% on natural gas. The remaining 11% consists of renewables such as hydropower (7%), wind (2%) and biomass (2%). To evaluate the impact of increasing wind penetration in Alberta, we model three scenarios with different rates of wind penetration and coal-fired generators progressively replaced by wind farms. We also model two wind profiles – one relies on data from a single wind monitoring site, the other on data from two sites. The scenarios are summarized in Table 1 and briefly described here.

1. *Base (without-wind) scenario.* In the base case, energy is produced by three generators: coal (with nameplate capacity of 4700 MW), combined-cycle gas (4000 MW) and hydropower (1000 MW). The coal and gas plants are base-load generators. In addition, to

satisfying demand in any given hour, it may be necessary to have a new peak-load (diesel or open-cycle gas) generator in place, as hydropower may not be able to meet peak demand at some times. Whether an additional peak generator is needed is determined endogenously in the model.

2. *Moderate (medium) wind penetration scenario.* Wind turbines are introduced to replace 1000 MW of coal-fired capacity. To do so, a great deal more wind capacity is required. Due to the intermittency of wind over the year, only 36% of the maximum potential energy of a wind turbine is available and thus to replace 1000 MW of coal, about 2800 MW of wind capacity is needed, which results in a level of wind penetration of 32% (normalized to peak demand). In the case of two wind farms, this will require 1478 wind turbines, 778 with a nameplate capacity of 1.8 MW each and 700 with a capacity of 2 MW. In addition to introducing wind power, we evaluate the need to add a new peak-power plant for those times when wind power is unavailable and hydropower from storage cannot cover the load.

3. *High wind penetration scenario*. A second wind scenario replaces 2000 MW of coal-fired capacity. In this case for the double farm model, 5600 MW of wind are needed (or 1556 turbines of 1.8 MW capacity and 1400 turbines of 2.0 MW capacity), which results in a level of wind penetration of 64%.[2] As in the previous scenarios, we let the model decide whether a new peak power plant is needed, and its capacity.

The model is calibrated using data for 2003. Electricity demand for Alberta for 2003 is available on an hourly basis from the Alberta Electric System Operator (AESO, 2005). A reserve

[2] Based on the Blue Mountain project in Ontario (50 MW installed capacity on 4500 ac), 2.7 MW of wind capacity can be installed per km^2. A 5 GW wind 'farm' in Alberta would thus require 1850 km^2. While this is a large area, it still constitutes less than 1% of the total farmland area of the Province.

margin of 10% is added to demand to guarantee the reliability of the system. Existing gas plants in Alberta are a mixture of cogeneration plants, combined-cycle gas turbines (CCGT) and open-cycle turbines. For simplicity, we assume that all existing gas plants are base-load CCGT and the new peak power generator is an open-cycle gas turbine.

Coal and gas prices are obtained from data for power plants operating in Canada (Nuclear Energy Agency and International Energy Agency, 2005). Natural gas costs are $C6/GJ, while coal is $1.9/GJ.[3] Both wind and water resources are considered to be available to operators at negligible cost.[4] Variable O&M costs (excluding fuel) are $3.95/MWh for open-cycle gas, $4.36/MWh for CCGT and $0.61/MWh for coal plants (Natural Resources Canada, 2004).

In the base-case scenario, fixed costs do not influence the optimal solution because generators are already in place. For the two wind scenarios, fixed costs for wind and peak (open-cycle gas) turbine generators are included in the cost function because they are added to the grid and the model determines how much additional peak capacity is required. Typical investment costs for wind power plants in Alberta are $1620 per kW of installed capacity, while they are $800 per kW for open-cycle gas turbines (Natural Resources Canada, 2004). In addition, these plants require fixed O&M costs of $39,600 per MW per year for wind and $9,500/MW per year for open cycle gas plants. Considering a plant lifetime of 25 years and a discount rate of 5%, the annualized cost of installing wind turbines is $155,000 per MW of capacity and $66,000/MW for

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[3] All monetary values are in Canadian dollars with $C1 ≈ $US 0.89.

[4] While wind might be a 'free' resource, water often has an opportunity cost, but only if water that generates electricity cannot be used elsewhere. In Alberta, hydro dams are located on the east slopes of the Rocky Mountains and are used for flood control and power generation. With few exceptions, water is not in short supply and then only in southern Alberta where it is used primarily for enhanced oil recovery (although CO_2 is increasingly being used) and agriculture. The value of water in agriculture is very low, some $0.002 per litre (Parris and Legg, 2006).

open-cycle gas plants providing peak power.

Ramp-up rates depend on each plant's design and operating conditions. Published data on ramp rates for large coal-fired plants suggest that it takes from 2 to 3 hours to ramp up from idle to full capacity (ESKOM, 2005). In our model, we assume that it takes three hours both to ramp up and ramp down coal-fired output. While combined-cycle gas turbines are usually more flexible, they are meant to deliver base load and not peak load power; hence, we assume it takes two hours to fully ramp up or ramp down production. We consider no ramp up constraints for hydropower or open-cycle gas as both are capable of providing peak load dispatchable power.

The model also tracks CO_2 emissions, so that it is possible to determine savings in emissions and costs when wind penetrates the grid. For this purpose, we use the following emission factors: 0.094 t CO_2 per GJ of coal consumed and 0.056 t CO_2 per GJ of gas consumed (Reinaud, 2004).

Wind data are taken from two monitoring stations in British Columbia – one located in the Peace Region of northeastern B.C., close to the Alberta border, and the other on the northern tip of Vancouver Island that has wind speeds closer to those that might characterize southern Alberta (BC Hydro, 2005).[5] Thus, we assume that there are two wind farms, one in the north and one in the south, so that they are affected by entirely different wind regimes. Each wind farm is assumed to supply one half of the total nameplate wind capacity in the system. We also examine the case where all of the wind is generated by a wind farm employing the wind profile from northeastern B.C. Transmission constraints are ignored.

[5] Actual wind speed data for Alberta are not currently available. Wind speed data from the Vancouver Island site are for 2002, while that from the northeastern B.C. site are for 2003, except for November and December when 2002 data are used.

The first wind farm consists of Vestas V80, 1.8 MW turbines with a hub height of 67 m, and relies on the wind profile from northeastern B.C. The second 'farm' consists of ENERCON E-70 turbines with rated capacity of 2.0 MW and hub height of 113 m. At each monitoring site, wind speed was measured 30 m above the ground and data are available at 10-minute intervals. The following relationship is then used to estimate wind speed at hub height (Patel, 1999): $W_2 = W_1(h_2/h_1)^{0.14}$, where W_2 is the wind speed at hub height h_2, W_1 is the wind speed at measured height h_1 (30 m), and 0.14 is a typical ground surface friction coefficient. We estimate wind power using the power curves provided by the turbine manufacturers (Vestas, 2005; ENERCON GmbH, 2005). Finally, the hourly power output data are obtained by averaging the 10-minute wind power values. It turns out that maximum power output from the wind farm based on Vancouver Island data is greater than that from the northeastern B.C. location, but that, despite this, average power output over the year is somewhat lower; thus, average power for the double wind farm model is also somewhat lower than for the single farm. Further, the coefficient of correlation between hourly wind speeds for the wind power output profiles is only 0.11, indicating that there is much less variability in the two wind farm case.

Comparing annual available wind power to its capacity in the two farm case, we obtain a wind capacity factor of 26%, which is comparable to that obtained at onshore sites found in Europe and the United States (Nuclear Energy Agency and International Energy Agency, 2005). Figure 1 shows wind power generation over the year when 778 turbines of 1.8 MW each and 700 turbines of 2 MW each are installed (medium wind scenario). As shown in the figure and despite two substantially different wind farm locations, there are 596 hours in the year (6.8% of the time) when wind power drops to zero, which implies that another energy source needs to be available for those times. If all wind power is generated at a single site, no electricity reaches the grid

22.3% of the time (or 1954 hours).

Most hydropower dams in Alberta are located in the North Saskatchewan River and Bow River basins. Instead of modeling several individual hydropower facilities, we consider one large hydropower plant of 1000 MW having a single dam that is fed by both rivers. We simulate water inflow data so that the average inflow over the year is 400 m^3/s, with the reservoir behind the dam fed equally by both rivers – each contributing an average flow of 200 m^3/s. River flow data are measured daily, and were obtained from the HyDat Database of Environment Canada (2005). The resulting flow profile for 2003 is shown in Figure 2. As is typical for the region, water flow is lowest during winter, peaks during May and declines through the summer, with another peak occurring as a result of autumn precipitation.

We assume that the reservoir for the 1000 MW hydro facility has a volume of 2000 million m^3, which is roughly equivalent to the amount of water consumed during two months. None of the hydropower plants in Alberta have a pumped storage system. Other design parameters for the 1000 MW hydropower plant are given in Table 2.

4 Results and Discussion

In this section, we estimate how much energy is dispatched from the power generators in each of the scenarios, the peak capacity requirements, and the net costs of wind penetration. In addition, we test the effect of enhancing the hydro generator and adding a pumped storage system to Alberta's electrical grid when there is significant wind generating capacity. The results are obtained by coding the mathematical program in GAMS and solving it using the CONOPT nonlinear solver (Brooke et al., 2005).

4.1 Impacts on coal and gas power plants

In all of the scenarios with two wind farms, coal provides base-load power, and operates at its capacity the entire time. In the one wind farm case under the high penetration scenario, however, we find that the coal generator needs to ramp up and down so that it operates at part load several times during the year (Figure 3). This increases fuel consumption as fuel efficiency falls when the coal-plant operates at part load rather than near full capacity (Kim, 2004).

The presence of non-dispatchable wind power has the greatest effect on how electricity is dispatched from the base-load CCGT power plant. Due to the intermittency of wind power, the CCGT generator needs to be adjusted continuously. In the case of a single wind farm, we find that the CCGT plant is completely turned off 34 times in the medium and 209 times in the high wind scenario (Figure 4). The gas plant operates more frequently when wind generation is spread over two regions – it is turned off only four times over the year in the medium wind scenario and 29 times (for a total of 65 hours) in the high wind scenario. As a result it provides substantially more electricity compared to the single wind farm case (27.1 versus 24.8 TWh over the year for the medium scenario). The reason that the CCGT power plant operates more frequently in the case of two wind farms is that the average wind speed is slightly lower than for the single farm, even though variability or intermittency of wind is reduced. Nonetheless, as in the case of coal, any increase in the frequency of adjustment to the CCGT plant will increases costs related to inefficiencies in fuel use and maintenance costs from unscheduled shutdowns, and might even require the re-design of the CCGT. Such costs have not been taken into account in the current analysis.

4.2 Peak capacity requirements

In the base scenario, coal provides base-load power, while medium- and peak-load demands are satisfied by gas and hydropower, respectively. In the scenarios where wind is introduced, these generators may not be sufficient for offsetting the intermittency that wind imposes on the electrical grid. Therefore, a new peak power plant needs to be incorporated in the system. The capacity of this new power plant depends on the level of wind penetration. In the medium-wind scenario with two wind farms (see Table 1), a peak power plant with a capacity of 379 MW is required, while, in the high-wind scenario, a plant of 1423 MW is required (Figure 5). The new peak power plant will operate for a limited amount of time during the year – less than 1% of the time (only 15 hours) in the medium-wind scenario and nearly 10% (813 hours) in the high-wind scenario. In the single wind farm case, the required capacity of a peak gas plant is higher (867 MW and 1876 MW in the medium and high wind scenarios, respectively) and the peak plant operates somewhat more hours each year.

4.3 Costs of wind power and CO_2 emission reductions

The costs of wind penetration are divided into (i) the direct costs of new wind generation (i.e., fixed costs of new turbines), and (ii) the costs (or savings) imposed on the grid – the change in costs relative to the base scenario of deploying electricity from coal, gas and peak generators. As indicated in Table 3, investment costs related to wind turbines are still the major cost component, but the costs associated with peak power generation are relevant and they rise with the degree of wind penetration. In the medium-wind scenario and single wind farm, the costs of generating peak power are 15% of the investment in wind turbines, while they are 29% in the high-wind scenario. In the case of the double wind farm, they remain below 3%.

The main reason for introducing wind power is to reduce CO_2 emissions. For evaluating the costs of CO_2 mitigation, the model keeps track of hourly CO_2 emissions of all generators in the different scenarios. For the single wind farm, the costs of reducing CO_2 emissions are \$41 per t CO_2 for the medium-wind scenario, and \$45 per t CO_2 for the high-wind scenario; they range from \$54 to \$56 per t CO_2 when energy is derived from two wind farms because of the somewhat lower total output of power in this case. These values are much higher than the \$15/t CO_2 limit on what large final emitters in Canada will have to pay for exceeding emission targets (Government of Canada, 2005) and the C\$30/t CO_2 that emission permits were trading at on the European exchange in early 2006. Note that these estimates do not account for the costs associated with the intermittent operation of fossil-fuel generators, nor the increase in CO_2 emissions when power plants operate at part load capacity (which would increase costs in the single than the double farm model). Overall, the cost estimates we provide can be considered a lower bound estimate of the costs of integrating wind power.

4.4 Impact of hydropower capacity and energy storage

It is generally acknowledged that, when wind or other intermittent energy sources are present in the grid, water storage in a reservoir is beneficial because it could be used for generating electricity when wind is unavailable or demand is high. In our system, the hydropower facility provides some storage benefits, but it is not sufficient to obviate the needs of additional fossil-fuel capacity (867 MW in the medium-wind scenario and 1876 MW in the high-wind scenario and single wind farm model). There are three ways for improving storage benefits so that the need for additional fossil-fuel capacity in the wind scenarios is mitigated:

1. Increase hydropower capacity by adding additional turbines. Hydropower can then deal with

higher peak loads and greater fluctuations in demand (after wind is taken into account). However, there might not be sufficient water behind the dam for accomplishing this goal.

2. Increase water storage capacity, although this may be physically impossible or economically too expensive.
3. Implement a system of pumped hydro storage.

The costs of implementing these different alternatives are site specific and, due to lack of information, are not taken into direct account in our analysis. Yet, the impacts on the electrical grid and on peak-load requirements can be estimated within our model.

We examine a number of scenarios (in the single wind farm model) that improve upon the current configuration of available hydropower and storage capacity, determining in each case the required new peak capacity. Results are provided in Table 4. These indicate that (1) by increasing the hydropower capacity (i.e., adding more turbines), the size of the peak generator is reduced. A reduction in the size of the peak generator results in lower fixed system-wide costs. (2) Increasing the storage volume in the upper reservoir decreases the use of the peak generator (i.e., less power is dispatched by the peak generator during a year). By reducing the use of the peak generator, system variable costs are lowered. (3) Adding a pumped storage system has an effect that is similar to that of increasing the size (volume) of the upper reservoir. Whether pumped storage (and construction of a down-stream reservoir) or an increase in the capacity of the reservoir behind the power dam is preferred will depend on costs, and on physical and political constraints.

5 Discussion

In this paper, a mathematical optimization model of an electrical grid was developed to assess the impacts of introducing intermittent (renewable) energy into the grid. This approach has several clear benefits over traditional simulation approaches. First, the model searches for the best possible hourly allocation of power output from a variety of generating sources so that total operating costs are minimized. This information is crucial for any system operator wishing to evaluate the efficiency of the electricity market. Second, the constrained optimization approach integrates in one model the intermittency of wind power with the energy storage capabilities of reservoirs. While storage is a necessary condition for electrical grids with high rates of wind penetration, our model provides guidance for designing cost-effective electricity systems. Third, for any level of wind penetration, the model estimates the optimal level of new capacity that will guarantee the reliability of a system. This contrasts with traditional simulation models for electrical grids where reliability is tested, but not in an optimal framework that guarantees it is met. Finally, the model is sufficiently flexible that different types of generators or energy storage devices can easily be added.

Our empirical application shows that an increase in wind penetration creates imbalance in the system and must therefore be countered with an increase in backup capacity via a new peak-load (open-cycle gas or diesel) generator that only operates for short periods during the year. This leads to rising system costs that will ultimately need to be passed onto the consumer. The costs of this additional peak-load capacity might represent some 15% to 30% of the investment costs of a wind farm, and are often ignored in the calculation of the benefits of wind power. Further, since the peak-load generator consumes fossil fuels, it also raises the costs of reducing greenhouse gas emissions.

The model was also used to demonstrate that there may be benefits from relying on wind power generated at two sites with uncorrelated wind profiles. Since the intermittency of non-dispatchable wind power is reduced, there is less 'wear and tear' on traditional thermal power plants as the frequency of 'stops and starts' is reduced. These benefits are offset, however, by the fact that average wind power might also be lower. This led to higher CO_2 mitigation costs in the two wind farm model as opposed to the single model. Future research might profitably examine the potential of wind power generated at locations dispersed across a sizable landscape.

The costs of wind penetration are lower if hydraulic storage is available, with electrical grids that are more dependent on hydropower better able to integrate intermittent wind and other such power sources. Cost effectiveness of intermittent sources is related to the share of hydropower in the grid. For those grids with less ability to store water for power generation, it might be necessary to increase the size of existing reservoirs and/or add a pumped storage system. However, the overall ability of hydropower to serve this function is subject to the vagaries of precipitation and possibly competition for water with agricultural, wildlife, industrial, commercial and residential users. In addition, many environmental groups oppose building more dams or higher ones, because of their destructive impact on fish and other wildlife habitat.

Further, because our focus was on CO_2 emissions and hydraulic storage, we leave to future research an application of the model to dynamic scenarios where the load is increasing over time and where new generating capacity could come from either wind or fossil-fired, thermal power plants. In that case, the additional system cost associated with wind might be lower and perhaps even less than the cost of meeting that same growth with a new fossil-fired power plant. However, this needs to be investigated further because of the vagaries of wind and the need to install more name-plate wind capacity than thermal capacity.

Finally, the model developed in this study is a simple representation of the allocation of power across generators in an electrical grid. Real-world electrical grids are much more complex, and operate in diverse ways that depend on the use of short versus and long term contracts and methods for determining day-ahead unit commitments and real time allocations to generators. The current model does not take into account these various nuances, but, rather, assumes rational expectations – that hourly electricity demand, water inflows into the reservoir and wind power availability are known a priori. Although sophisticated forecasting tools can be used to forecast demand with a high degree of confidence, and project future wind availability and precipitation relatively accurately, future research needs to examine alternative mathematical programming approaches that could better deal with uncertainty issues.

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Table 1: Installed capacity of power generators in the different scenarios (MW)[a]

Scenario	Coal	Gas	Hydro	Single Wind[b]	Double Wind[c]
Base	4700	4000	1000	0	0
Medium wind	3700	4000	1000	2770	2800
High wind	2700	4000	1000	5540	5600

[a] Peak demand is 8786 MW. New peak capacity is determined endogenously in the model.
[b] Single wind farm using wind profile from northeastern B.C., with 1539 1.8 MW wind turbines in medium wind scenario and 3078 turbines in high wind scenario.
[c] Two wind farms using wind profiles from northeastern B.C. (with 778 and 1556 wind turbines of 1.8 MW capacity in the medium and high wind scenarios, respectively) and northern Vancouver Island (with 700 and 1400 wind turbines of 2.0 MW capacity in the medium and high wind scenarios, respectively).

Table 2: Data Summary

Parameter	Value / Comments
Demand data	Alberta for year 2003. A reserve margin of 10% was added to demand to guarantee system reliability
Fixed costs for new capacity (including fixed O&M)	Peak (Gas open cycle): $66,000/MW-yr Wind: $155,000/MW-yr
O&M variable costs excluding fuel	Coal: $0.61/MWh CCGT: $4. 36/MWh Peak: $3.95/MWh Wind and Hydropower: $0
Thermal efficiency:	Coal: 37% CCGT: 49% Peak: 30%
Fuel price:	Coal: $1.9/GJ Gas: $6/GJ
CO_2 emission factors:	Coal: 0.094 t CO_2 per GJ of coal consumed Gas: 0.056 t CO_2 per GJ of gas consumed Hydro and wind power: zero
Ramp-up constraints. Time required for starting up to full capacity	Coal: 3 hours CCGT: 2 hour Wind, hydro and peak: less than one hour
Ramp-down constraints. Time required for turning down from full-capacity to zero	Coal: 3 hours CCGT: 2 hours Wind, hydro and peak: less than one hour
Wind speed data from:	Monitoring stations located in the Peace River region of British Columbia
Hydropower plant:	Average inflow: 400 m^3/s Maximum outflow: 1134 m^3/s Storage volume: 2000 million m^3 Volume of the reservoir at the beginning and end of the year: 1000 million m^3 Overall turbine efficiency: 85% Maximum head: 106 m Minimum head: 92 m Pumped storage: not available
Inflow data for hydro generator:	Bow and North Saskatchewan Rivers in Alberta

Table 3: Costs of wind penetration (as compared with the no-wind scenario)

	Single-wind farm scenario[a]		Two-wind farm scenario[b]	
Item	Medium wind	High wind	Medium wind	High wind
	($ millions per year)			
Investment in wind turbines	429.4	858.8	434.0	868.0
Costs imposed on the grid (negative indicates savings):				
Coal generation	-167.3	-341.0	-167.3	-334.6
Gas generation	-1.8	-56.9	113.7	228.0
New Peak generation	64.8	250.6	0.1	20.0
Net costs of wind penetration:	325.1	711.5	380.5	781.4
	$ per MWh			
Costs per MWh	5.2	11.3	6.1	12.5
Reducing CO_2 emissions	Mt CO_2			
CO_2 savings	7.985	15.678	7.045	13.910
	$/t CO_2			
Cost per t CO_2	40.71	45.38	54.01	56.18

Table 4: New peak capacity requirements under different hydropower and storage scenarios

Scenarios[a]				
Hydropower capacity (MW)	Storage capacity of upper reservoir (million m^3)	Pumped storage	Peak capacity required (MW)	Electricity produced by peak generator (GWh)
Benchmark (Medium Wind)				
1000	2000	No	867	100
Alternative scenarios				
1000	4000	No	867	66
1000	2000	Yes	867	66
1500	2000	No	367	74
1500	2000	Yes	367	11
1500	4000	No	367	4
1500[b]	4000[b]	Yes[b]	367	4

[a] In all scenarios, the inflow of water into the upper reservoir is the same, while the capacity of the lower reservoir is constant at 1000 million m^3 where applicable.
[b] In this scenario a pumped storage system was added. The model determined, however, that such system would not be used.

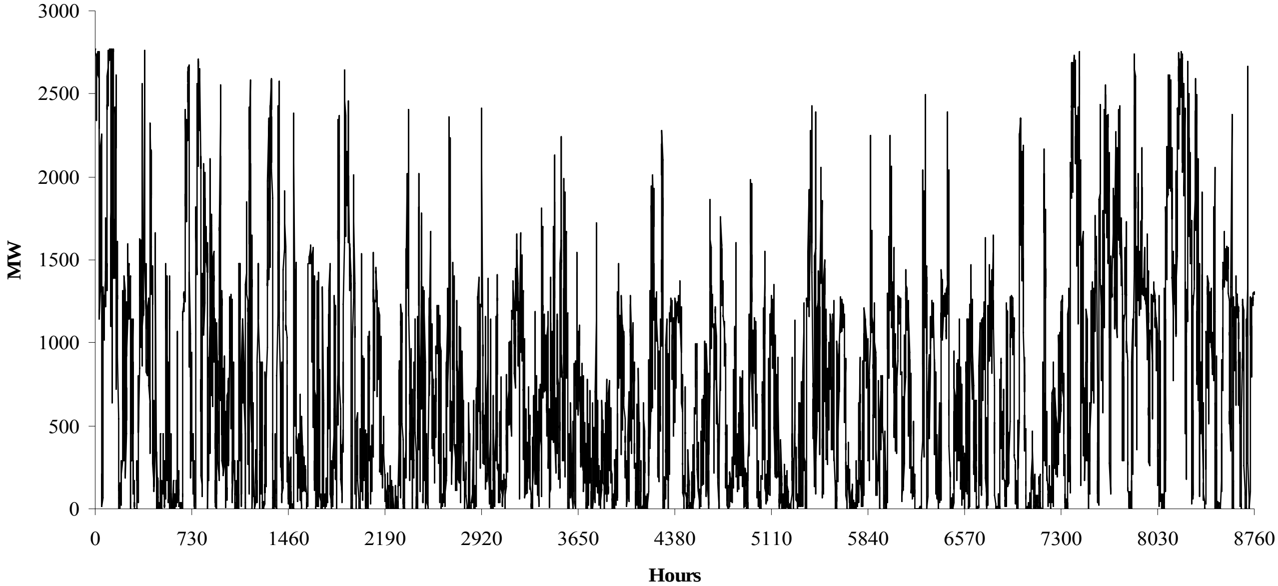


Figure 1: Estimated power generation from two wind farms with combined capacity of 2800 MW

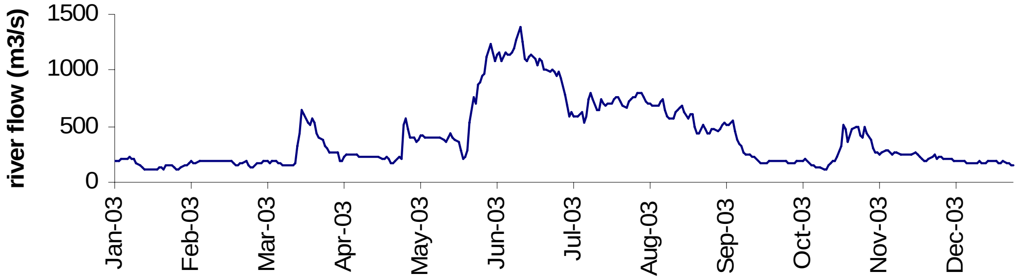


Figure 2: Water inflow to the hydropower reservoir

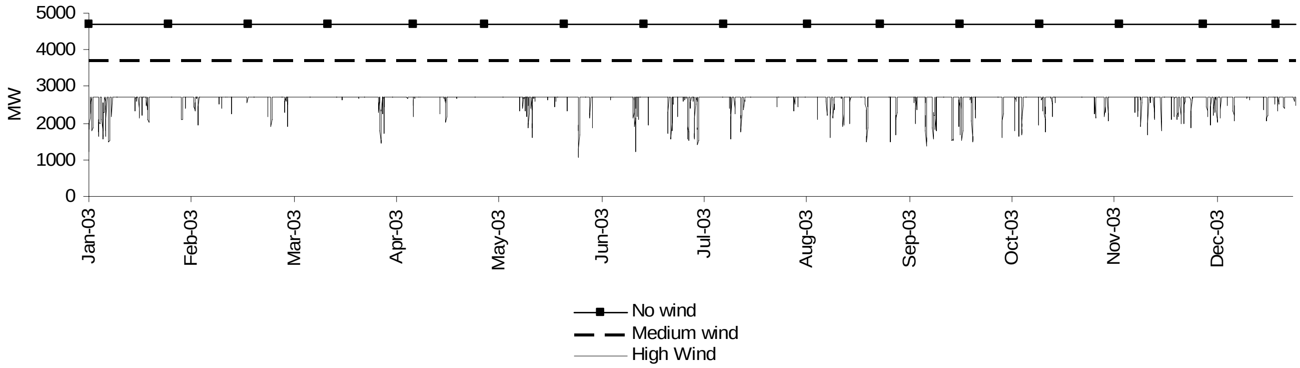


Figure 3: Electricity dispatched by the coal power plant in the single wind farm model

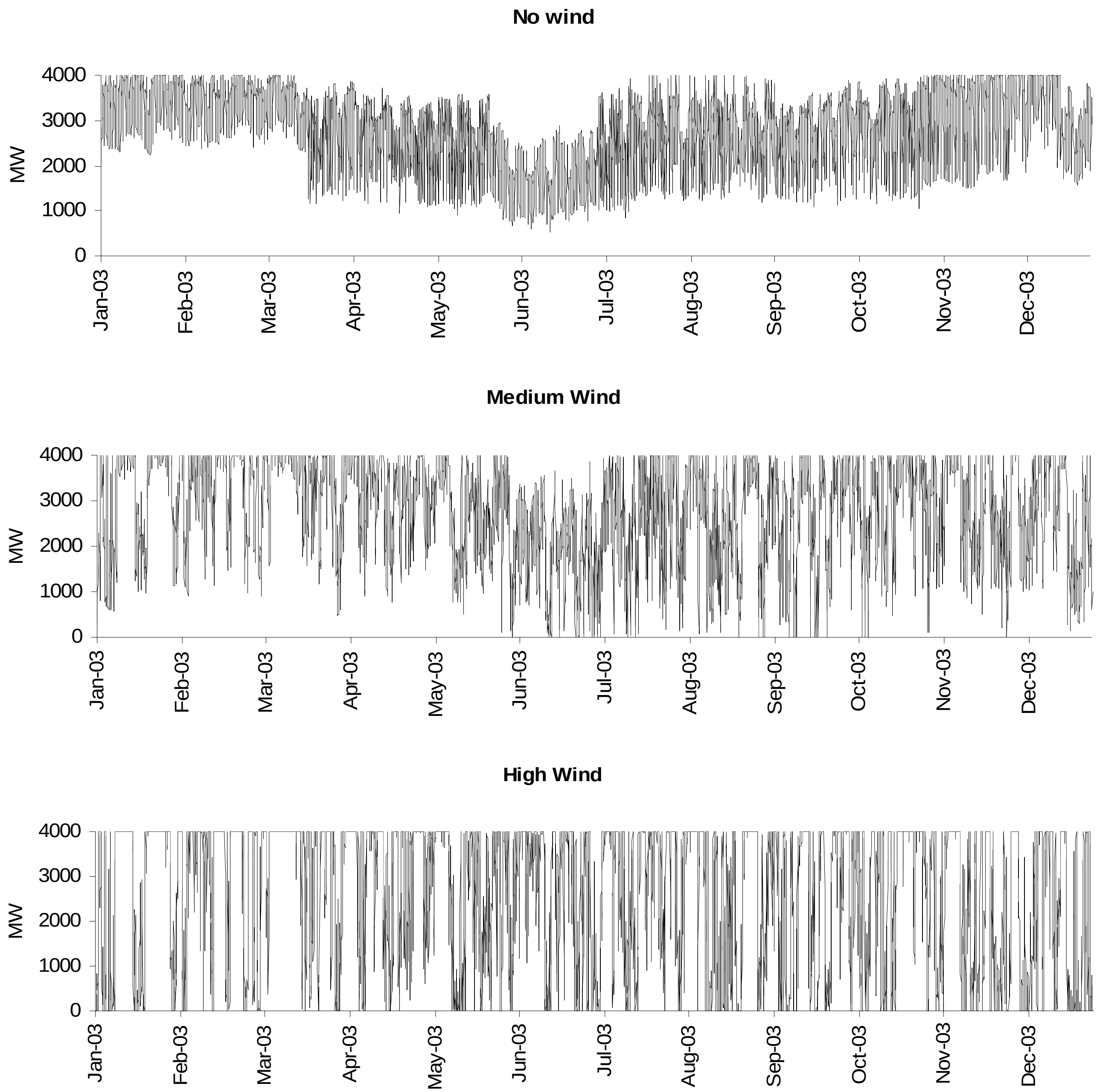
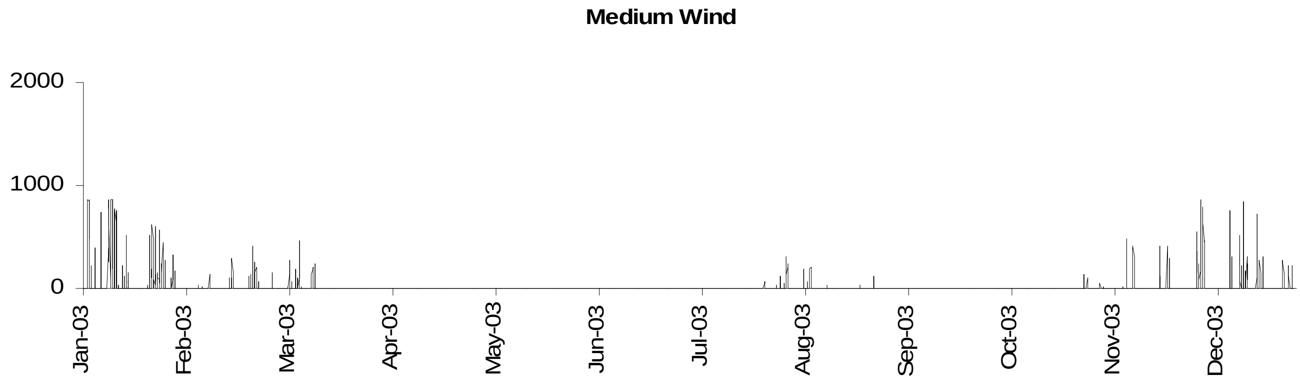


Figure 4: Electricity dispatched by the (combined cycle) gas fired power plant, single wind farm model



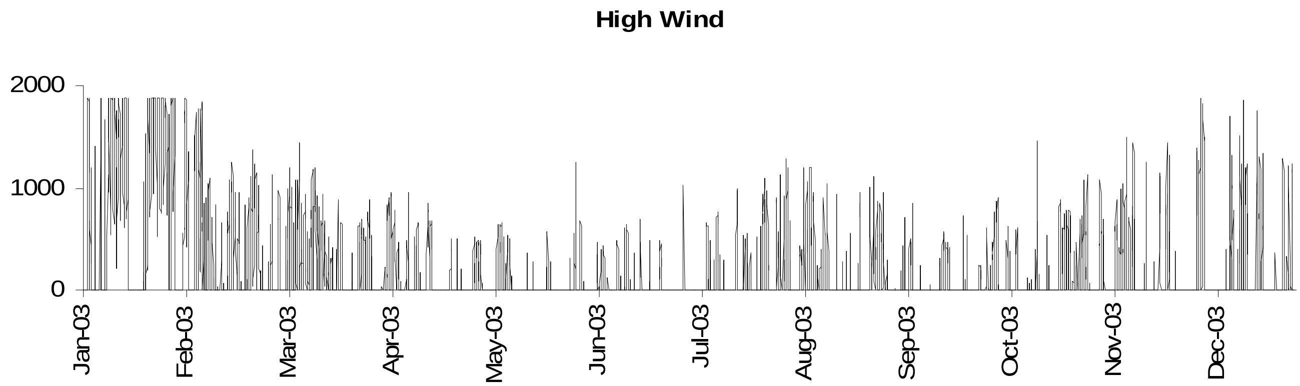


Figure 5: Electricity dispatched by the new peak power generator, single wind farm model