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Wind Integration into Various Generation Mixtures

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Wind Integration into Various Generation Mixtures

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Abstract

A load balance model is used to quantify the economic and environmental effects of integrating wind power into three typical generation mixtures. System operating costs over a specified period are minimized by controlling the operating schedule of existing power generating facilities for a range of wind penetrations. Unlike other studies, variable generator efficiencies, and thus variable fuel costs, are taken into account, as are the ramping constraints on thermal generators. Results indicate that system operating cost will increase by 15% to 110% (pending generation mixture) at a wind penetration of 100% of peak demand. Results also show that some mixtures will exhibit cost reductions on the order of 13% for moderate wind penetrations and high wind farm capacity factors. System emissions also decrease by 13% to 32% (depending on generation mixture) at a wind penetration of 100%. This leads to emission abatement costs in the range of \$65 per tonne-CO_2e for coal dominated mixtures, but \$450 per tonne-CO_2e for hydro dominated mixtures. For natural gas dominated mixtures, the introduction of wind power may well be beneficial overall.

Keywords: Wind power integration; generation mixtures; emissions cost.

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1. Introduction

Global electricity demand is rapidly increasing as rich countries continue to expand and developing ones grow even faster; yet, power demand will still be met primarily by carbon-based fossil fuels (especially natural gas and coal) into the foreseeable future [1, 2]. Due to climate effects, air quality issues and questionable supply security of hydrocarbon sources, national decision makers increasingly emphasize deployment of less carbon intensive and more sustainable (local) electricity sources. As a result, wind power has gained considerable momentum, with current global installed capacity of 74 GW projected to reach 160 GW by 2010 [3].

The cost and emission impacts of adding wind capacity to an electricity system depends on the existing generating technology and mix of generators. Introducing the same wind resources into various electricity systems will result in quite different economic and environmental impacts. To understand the potential wind power effect on costs and emission offsets, an analysis of wind integration into various technology mixtures is required.

Study after study of wind systems has reached the same conclusion: Wind power can provide environmental and economic benefits when its proportion of demand is small, but financial costs rise rapidly and environmental benefits fall dramatically as its proportion of demand increases [4 – 8]. Wind power is a non-dispatchable and highly intermittent electricity source that induces large variability on extant system generators when wind is introduced. In attempting to balance the demand that is unmet by wind, existing generators will ramp up and down more often and operate more frequently at reduced capacity, thereby lowering average capacity factors and average operating efficiencies. The need to ramp existing generators up and down to follow wind is a particular problem, with generating mixes that have fast-ramping generators better able to integrate wind. Even so, ramping limits throughout the system may lead to excess generation in some periods, thus adding to the cost of a wind farm installation. When generating facilities operate at a sub-optimal level as wind power replaces thermal power, the decrease in efficiency corresponds to an increase in per unit fuel consumption (on an energy output basis), thereby raising CO_2 emissions intensity and fuel costs. The increase in system costs imposed by ramping constraints and the increase in fuel costs at existing facilities from sub-optimal operation must be taken into account when assessing the feasibility of wind installations [4, 6, 7]. Results from wind integration studies are heavily dependant on the temporal alignment between the wind resource, the electric demand, and the operating schedule of existing generators. Previous studies [9, 10] have addressed this sensitivity by performing a variance analysis, where the wind profile is temporally shifted with respect to the demand profile. This study performs a similar analysis, shifting the wind resource profile; but we augment this variance analysis by considering multiple generating technology mixtures.

The purpose of this study is to quantify the economic costs and environmental effects of integrating intermittent wind power into electricity systems with differing generating mixtures. Variable operating efficiency and ramp rate limits are taken into account, as are typical variable and fixed O&M costs and capital costs. The research extends previous work by the authors [11] that examined wind integration into a hydroelectric dominated mixture only. The current study considers the economic and environmental performance of three appreciably different combinations of generating mix when varying amounts of wind power are integrated into the respective systems.

2. Electricity Generating System Model

2.1 Overview

An electricity system is modeled with five traditional generation technologies: a natural gas combined cycle (NG CC), a petroleum combined cycle (P CC), a pulverized coal steam cycle, large-scale hydroelectric, and nuclear power. Three significantly different generating mixtures representing the aggregate generating mixes of Canada, the United States and the U.S. Northwest Power Pool are investigated. Increasing amounts of wind capacity are added to each mixture and system performance is quantified over a specified period using the same demand profile in each case.

The model's objective is to minimize the overall operating cost of the generating system over a specified period. Included in the objective function are fuel cost, variable O&M cost, fixed O&M cost and capital cost for the wind farm only, as the wind farm is the only new installation. Typically an average fuel cost is calculated with respect to an average operating efficiency, translating the cost of an energy source to the fuel cost of producing electricity. In the present study fuel costs increase as a generator operates at less than optimal efficiency, as is the case when wind power penetrates the system. This increases fuel consumption intensity and associated fuel costs for an individual generator.

The system model is described in detail elsewhere [11]. For the current analysis, transmission constraints have been removed so as to focus only on the impacts of different generation mixes. Operating restrictions for thermal power plants include the rate at which a generator can ramp output up or down as well as minimum and maximum capacities. The level of ramp rate restriction placed on a particular thermal generator depends on the type of facility. Coal and nuclear power plants are considered to be base load facilities that would not typically operate at low capacity. Hence, the model constrains these facilities to operate between 50 and 100% of their capacity, and to never shut down.

Results from this study depend on the temporal alignment between the wind resource and system demand, so they are sensitive to single events (e.g., simultaneous occurrence of high load and no wind). To avoid this, the wind speed profile is shifted by one, two, three and four weeks in both directions against the load profile. This enables one to identify anomalies surrounding single events and provides insight regarding the month-scale seasonality of a wind resource.

Existing generators are considered ‘dispatchable’ – they can withhold power from the grid (as spinning reserve) and can ramp up or down (with limitation) when requested to do so. Wind output is considered ‘must run’, so the network must absorb wind power whenever it becomes available. Due to this ‘must run’ constraint on wind, the ramping restrictions on thermal generators and the minimum operating levels for coal and nuclear, there may be periods when total generation greatly exceeds total demand. An additional sink is placed in the system to absorb excess power if required; this sink can be thought of as an export or energy storage opportunity. The export sink, variable efficiency for generators, ramp rate limitations and minimum operating levels are all modeled as linear constraints in the constrained optimization procedure. It is also assumed that generator costs vary linearly with capacity factors, although in reality these trends are non-linear.

The optimization problem is formulated as a quadratic program with linear constraints, and solved over two-week periods using an hourly resolution and minimizing total generation cost. The program is written in Matlab with an interface to Excel and calls to the optimization routines in GAMS [11].

2.2 Model Parameters

The Vancouver Island electric system is used as the base for sizing absolute generator capacities and demand for the three regional mixtures (the relative capacities are determined by the particular mix.) Vancouver Island is used as a metric due to the availability and resolution of demand and wind speed data. There is a total of six individual generators, with a combined capacity of 2054 MW and peak load of 1971 MW. Demand data for Vancouver Island are from BC Hydro [12] in the form of hourly load for the entire island during 2003. A 336-hour load profile (actual demand for December 18-31, 2003) is used to demonstrate network operation over a high (winter) demand period. A plot of the winter demand profile can be found in [13], and has a total energy demand of 508 GWh.

In this study, the Canada aggregate, United States aggregate and North West Power Pool (NWPP) mixes are modeled with various amounts of additional wind capacity integrated into the mixtures. The total capacity of each region is scaled to match the total capacity of the Vancouver Island system (2054 MW), and the individual generator capacities are sized to reflect their respective proportions in their original mixture. Generating technology and capacity for each individual generator in each mix is provided in Table 1. The Canada aggregate (CAN) mix was obtained from the Canadian Electricity Association [14], while the US aggregate and NWPP mixtures are from the Energy Information Administration [15]. Except for hydro, the existing renewable capacity in each region is ignored because it makes little contribution to the power mix. The natural gas (NG) and petroleum (P) fed generators in all regions are assumed to use combined cycle technology only, while all coal fed generators are assumed to use only supercritical pulverized coal technology. The percentage breakdown of each technology in each mixture is shown graphically in Figure 1.

To calculate variable fuel cost, two elements are required for each generator: the efficiency trend with respect to varying part load, and the cost of fuel for that generator in Canadian dollars per MWh (with $ henceforth representing CAD unless otherwise indicated). Typically fuel costs are in dollars per Giga-Joule (GJ) or Million-Btu (MMBtu), with natural gas costing $8.62/GJ ($US8.0/MMBtu) [16]. We convert $/GJ or $/MMBtu to $/MWh, so that a MWh of electric energy can be directly compared to a MWh of fuel energy. For example, assume that a NG CC generator is operating at 50% efficiency. Therefore, it takes two MWhs of natural gas to produce 1 MWh of electricity, with the associated CO_2 emissions corresponding to those of combusting two MWhs of natural gas. If the efficiency of the generator varies with respect to its part load, then, as the generator ramps down from full capacity, efficiency falls and it takes more than two MWhs of natural gas to produce one MWh of electricity. The cost trend has a negative slope with respect to generator part load: at full capacity the fuel cost ($/MWh$_e$) is the least, and at the lowest capacity the fuel cost is the most. The resulting cost curve for each generator (with respect to part load) is approximated with a linear function:

$$Cost_{fuel}[CAD/MWh_e] = A_f \cdot PL + B_f \,, \quad (1)$$

where $Cost_{fuel}$ is the fuel cost of operating a generator at a given part load, PL is the part load of the generator ($0 \leq PL \leq 1$), A_f is the slope of the linear cost trend (typically negative), and B_f is the intercept term.

The constants A_f and B_f that describe the variable fuel cost for the various generators are provided in Table 2. Natural gas [16], coal [17] and petroleum [18] spot prices are used to calculate generator fuel cost, and have values of $8.62/GJ ($US8.0/MMBtu), $1.53/GJ ($US1.42/MMBtu) and $13.03/GJ ($US12.08/MMBtu), respectively. Natural gas combined-cycle part load efficiencies are taken from [19], with the part load efficiency curve for the NG CC used for the P CC technology as well. Pulverized coal part load efficiencies are taken from [20], and are considered over a load range of 50% to 100% of generating capacity.

For the hydro facilities, the constants A_f and B_f are calculated using water license rental rates associated with power production for 2006 [21], which can be regarded as fuel costs. The rental rates are $1.086 per generated MWh and $0.006 per 1000 m^3 of throughput water. These dollar amounts are used in conjunction with part load efficiencies for a Francis hydroelectric turbine [22], an average head height and average peak flow rate taken from British Columbia hydro facilities. The A_f and B_f constants for the hydroelectric generators are also provided in Table 2. Note that the fuel costs for the hydroelectric facilities are a fraction of those for the hydrocarbon facilities as water rental rates in British Columbia are low, while hydrocarbon prices are high.

Fixed and variable O&M costs are also provided in Table 2 for all generators, and were obtained from [23], as were the CO_2-equivalent emission factors for combusting natural gas, petroleum and coal. The total variable generation cost includes both variable fuel cost and variable O&M cost. Variable fuel cost fluctuates with respect to generator part load (Equation 1), but the variable O&M cost remains constant irrespective of generator part load. Fixed O&M cost for each generator is added to the total system operating cost after the optimization procedure, as this cost is not affected by the dispatch schedule, or the energy output from the generators.

The variable cost of operating nuclear facilities is held constant regardless of part load operating level. Fuel and variable O&M costs [24] are assumed to be $6.63/GJ ($US6.15/MMBtu) and include uranium cost, fuel preparation, variable O&M and provision for spent fuel. The cost of $6.63/GJ represents an average cost for U.S. nuclear facilities [24]. A fixed O&M cost [23] is also applied to nuclear facilities after the optimization procedure, and is also listed in Table 2.

All thermal generators are modeled with ramp rate constraints. The coal and nuclear facilities are the most heavily constrained, with full ramp up and down times of three hours. A full ramp time of three hours implies that these facilities can only ramp up or down one third of their capacity in a single hour. Natural gas and petroleum combined-cycle generators are modeled with full ramp up and down times of two hours. Hydroelectric generators are without ramp rate constraints. The mix of high (coal and nuclear facilities), medium (natural gas and petroleum facilities), and low (hydro facilities) ramp rate constraints is shown graphically for the regions in Figure 2.

Actual wind speed data are used to calculate the power output from a wind farm. The observed wind speed is assumed to be experienced over the entire area of the wind farm with no dispersion effects (all turbines see the same wind speed at the same time). The assumption of rational expectations on the part of the system operator extends to wind power availability as the operator is assumed to predict wind speeds perfectly with no forecast error. The 336 data points (hourly wind speed over two weeks) used for this exercise were observed at Jordan Ridge on Vancouver Island (Lat: 48 25 48, Long: -124 03 45) from August 19 to September 1, 2001, at a height of 30 m above the site elevation of 671 m [25]. A plot of the wind speed profile and the output from a single Enercon E70 can be found elsewhere [13]. The wind speed is measured at 30 m, but was scaled exponentially to correspond to a turbine hub height of 113 m [26]. As discussed previously, the wind speed profile was shifted by up to four weeks in each direction against the demand profile. The temporal shift of the profile is with respect to the zero-shift dates (Aug 19 – Sept 1).

3. Results and Discussion

3.1 System Operating Cost

System operating cost was minimized for each mixture for a range of wind farm capacities (wind penetrations). Wind penetration refers to the ratio of the wind farm installed capacity divided by the peak system load (1971 MW). Results are plotted in Figure 3, where the effect of wind penetration on system operating cost for three different but typical generation mixtures are indicated. Apart from quantifying the economic effect of wind power, this figure will aid in determining which type of generation mixture can reap the largest benefit from wind power. Operating cost is calculated by summing all the various system costs over the two-week period and dividing by the energy demand met in that period (yielding a cost with units of $/MWh). Fuel costs, variable and fixed O&M costs, and capital cost of the wind farm are all included in the operating costs shown in Figure 3. Capital costs for generators other than the wind farm are not included because new wind capacity is introduced at varying levels into a pre-existing mixture. Wind farm capital cost is set at $600/kW [27], and amortized over a life of 20 years at a discount rate of 10%.[1] The annualized cost is then multiplied by 336/8760 to represent the two-week wind farm capital cost. As wind penetration grows, the installed capacity of the farm grows and so does the capital cost for the installation.

At zero wind penetration, the operating cost difference between the three mixtures is evident. The CAN mix has the lowest system cost ($12.5/MWh) because the majority of

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[1] This is an optimistic value that presumes costs of wind installations will decrease as the technology matures. The Energy Information Administration assumes a 2005 wind farm capital cost of $1167/kW [21].

capacity comes from hydropower. The US mix is bracketed between the others ($24.5/MWh) due to the high percentage of moderate cost coal capacity, while the NWPP system is the most expensive ($30.5/MWh) due to the high percentage of NG capacity.

For the CAN mix, wind mostly replaces inexpensive hydro power and the reduction in existing fuel cost is modest. As wind penetration grows, wind capital and fixed O&M costs overcome any reductions in fuel and variable O&M costs of existing generators and total operating cost increases for the entire range of wind penetration. At a wind penetration of 100%, the costs of the CAN system have increased by $14/MWh, or by 110% compared to the cost of operating the system without wind power. Average capacity factors for generators in the CAN mix for various wind penetrations are shown in Figure 4. As wind penetration grows, the average capacity factors for the two hydro facilities are reduced by more than 20%, illustrating that wind power mostly replaces hydropower. Nuclear and coal facilities have greater fuel costs compared to hydro facilities and should be replaced before hydro to obtain the largest cost reduction, but they are unable to be largely substituted by wind due to the minimum operating constraint of 50% capacity on these technologies. The NG and petroleum facilities are already near zero capacity at zero wind penetration and do not provide the opportunity to be replaced by wind power.

For the US system, wind power mainly replaces hydro, coal and nuclear generation and a $4.5/MWh decrease in fuel costs results at a wind penetration of 90% (Figure 6).[2] The reduction in fuel cost is still not enough to overcome the increasing cost of wind capital and fixed O&M, with total operating cost increasing over the entire range of wind penetrations.

[2] For the US mixture, wind penetration can only grow to 90% before the capacity of the system export sink attains its limit. The US mix has 70% of its capacity restricted to operate above 50% part load (coal and nuclear), so periods of high wind penetration and high coal and nuclear generation result in a large amounts of exported power.

At a wind penetration of 90%, costs increase by $9/MWh for the US mix, a 37% increase compared to the cost of operating the system without wind power.

The average capacity factors for the generators in the US mixture for a range of wind penetrations are indicated in Figure 5. As wind penetration grows, the average capacity factors for the hydro, coal and nuclear facilities are all reduced by approximately 20% at 90% wind penetration, indicating that wind mostly replaces these capacities. The capacity factor for the NG generator is also reduced, but only by 6% at a wind penetration of 90%. The average capacity factors for the coal and nuclear generators are not reduced to their limit of 50% (as one would expect with minimum operating cost) due to the sheer size of their capacity. These large generators are required to meet demand even for high wind penetrations, due to times when wind speeds are low and wind capacity cannot produce significant energy.

Figure 6 shows the breakdown of total operating cost for the US mix, with fuel, variable O&M and fixed O&M costs for existing generators, fixed O&M costs for the wind farm, and the capital costs for the wind farm independently plotted. Wind farm capital and fixed O&M costs (wind fixed costs) increase linearly with wind penetrations, with respective values of $9.5/MWh and $4.5/MWh at 90% wind penetration. The increase in wind fixed costs is the same for each mixture, increasing operating costs by $14/MWh at 90% wind penetration. Any reduction in fuel and variable O&M costs for existing generators directly reduces the effect that wind fixed costs have on total operating costs. For the US mixture, fuel costs for existing facilities decrease by $4.5/MWh and variable O&M costs for existing generators only fall by $0.5/MWh, or by $5/MWh in total at 90% wind penetration. This reduction in fuel and variable O&M costs is not sufficient to combat the rising wind fixed and total operating costs for the full range of wind penetration.

For the NWPP mix, wind power replaces NG, coal, nuclear and hydro generation. For a wind penetration of 30%, costs decline by only $1.5/MWh, but for higher penetrations wind fixed costs again override reductions in fuel and variable O&M costs and total costs increase for the larger range of wind capacities. At a penetration of 100%, costs are higher by $4.5/MWh, a 15% increase compared to the costs of operating the system without wind power. Figure 7 shows the average capacity factors for the generators in the NWPP mix for the range of wind penetrations. The NG, coal and nuclear generators all experience a 15% reduction in capacity factor over the range of wind penetrations in the figure. Reducing the use of the expensive NG facility (as well as the coal and nuclear plants) leads to a large drop in system fuel costs for the NWPP mix, by $10/MWh at a penetration of 100%.

3.2 Temporally Shifting the Wind Profile

The effects on operating costs of shifting the wind profile in relation to the demand profile are indicated in Figure 3. The main trend line for each mixture is the operating costs without wind shifting, and the error bars indicate the range of costs when the wind profile is shifted from one to four weeks in either direction. Operating costs vary because each wind profile produces a different profile of wind power availability and hence differing responses from existing generators. The energetic capacity factor of a wind profile aids in explaining the resource potential for that wind profile; these are provided for each of the nine shifts in Figure 8. The capacity factors for the various profiles range from 8% to 28%, with the original ('no shift') profile providing a factor of 23%. The effect of each wind shift can be better seen in Figure 9, where the operating cost for the US mixture is plotted for each of the nine profiles. The operating costs for the original profile fall roughly in the middle of the other plots of costs; profiles with higher capacity factors result in lower operating costs, and profiles with lower capacity factors result in higher operating costs. High wind capacity factors result in lower operating costs because more wind energy is available for replacing existing generation. Figures 8 and 9 together show that the capacity factor of the wind resource is the driver that alters the effect of wind power on system performance, not single events that may occur in temporal matching of the wind resource and demand.

In regards to system operating costs, the NWPP mix shows the largest change with respect to wind shifting, with the US and CAN mixtures exhibiting lesser effects. For the CAN mix, a greater amount of available wind energy simply replaces a larger portion of low cost hydropower with only small changes in operating costs ($2/MWh). For the US mix, a greater amount of wind energy is able to replace both coal and nuclear generation, and operating costs can vary by $3.5/MWh due to wind shifting. For the NWPP mix, more wind energy can replace more expensive NG capacity, with the largest change in operating costs ($8/MWh) due to wind shifting. The "-2 weeks" shift yields the lowest operating costs for the NWPP mix, reducing costs by $4/MWh at a penetration of 40%, or by 13% compared to the costs of operating the system without wind power.

3.3 Costs of Reducing Carbon Dioxide Emissions

Apart from quantifying the effect of wind on system operating costs, the effect of adding wind power on CO_2 emissions is also examined. Emissions are calculated using the same method as with costs: summing all emissions over the two-week period and dividing by total energy produced, yielding an emissions factor with units of kg-CO_2e/MWh, where the CO_2e refers to carbon dioxide equivalent A plot of emission factors for each mixture over the range of wind penetrations is shown in Figure 10. Emissions produced by each mixture without the use of wind power are 130, 220 and 510 kg-CO_2e/MWh for the respective CAN, NWPP and US mixes. The large difference in emissions between the CAN-NWPP and US mixes is due to the high use of emission intensive coal in the latter. Environment Canada reports a Canadian average emission factor of 217 kg-CO_2e/MWh [28], with the discrepancy with our value of 130 kg-CO_2e/MWh due to the greater actual use of coal.

As wind penetration increases to 100%, all mixtures exhibit a reduction in emissions, which is expected as zero emission wind replaces CO_2 emitting thermal generation. At 100% wind penetration, the CAN, NWPP and US mixes reduce emissions by 17, 70 and 85 kg-CO_2e/MWh, respectively, or by 13%, 32% and 17% compared to operating without wind power. Shifting the wind profile results in a maximum variation of 10, 75 and 80 kg-CO_2e/MWh for the respective CAN, NWPP and US mixes. When more wind energy is available, it is possible to reduce emissions to a larger degree for the US and NWPP systems than the CAN one, because wind replaces both coal and NG to a greater extent.

CO_2 emissions in the CAN mix do not vary much with wind penetration or wind shifting, because wind power mostly replaces zero emissions hydropower. The US mix has the greatest absolute reduction in emissions (85 kg-CO_2e/MWh), but this represents only a 17% relative decrease due to the large amount of emissions present in the system before wind power integration. The largest relative decrease in emissions occurs in the NWPP mix, with emissions reduced by 75 kg-CO_2e/MWh from initial emissions of 220 kg-CO_2e/MWh. System emissions are low compared to the US system, because of the higher proportion of NG capacity relative to coal, but the replacement of both by wind energy still enables a large 32% reduction in emissions.

By combining information from Figures 3 (cost increases) and 10 (emissions reduction), the costs of abating emissions for various mixes can be determined. The results are provided in Figure 11, where marginal emission costs are quantified for each mixture and penetration level. Costs are highest in Canada where the cost of abating emissions is estimated to range from $160 to $770 per tonne-$CO_2$e over the range of wind penetrations investigated here. High emission costs for the CAN mix are due to low emission reductions coupled with high cost increases, both of which are related to the high degree of hydropower in the mix. The US mix exhibits more realistic carbon costs of $35-$100/tonne-CO_2e, still above prices at which CO_2 has recently been trading in European markets (about $32 per tonne).[3] The lower US costs for emissions reduction are due to the large reduction in emissions associated with the replacement of coal by wind and moderate cost increases – an 85 kg-CO_2e/MWh reduction in emissions and a $9/MWh increase in cost at 90% wind penetration. As indicated in Figure 11, costs of marginal emissions reductions are negative for the NWPP mix over some range of wind penetration, which means that overall electricity generating system costs can be reduced by using wind to reduce CO_2 emissions (as explained in section 3.1). The benefits of reducing emissions range from -$50 to $0 per tonne-$CO_2$e for wind penetrations up to 50%, but rise to $60/tonne-$CO_2$e at a penetration of 90%.

4. Conclusions

In this study, a power balance model was formulated that considered the interaction between existing generation mixtures and newly installed capacities of wind power, minimizing the total operating cost of the system. Three systems consisting of different combinations of natural gas, petroleum, coal, nuclear and hydro generating facilities,

[3] As of 27 June 2007, CO_2 was trading in Europe at €21.58 (http://www.pointcarbon.com/). This is multiplied by 1.5 to convert to Canadian dollars.

normalized to a small Vancouver Island system, were considered in order to examine how generating technologies affect the feasibility of wind power penetration. Sensitivity analysis was conducted by varying the wind profile for each representative generation mixture.

Results indicated that a wind penetration of 100% increases operating cost for systems similar in generation mix to the aggregate Canada and aggregate US systems by \$14 per MWh (110% increase) and \$9/MWh (37% increase), respectively. Wind integration into the NWPP mixture, on the other hand, reduced costs by \$1.5/MWh at a wind penetration of 30%, but increased costs by \$4.5/MWh at 100% wind penetration (15% increase). Time shifting the wind profile (varying the wind farm capacity factor) made little difference for CAN and US type mixes, varying cost by a maximum of \$2-\$3.5/MWh, while varying operating costs more significantly (some \$8/MWh) for the NWPP mixture, with a decrease of 13% at a wind penetration of 40%. Indeed, it turns out that the capacity factor of wind over a time-period is a better indicator of the impact of wind penetration than is the actual temporal wind power production profile.

Wind integration also reduced system-wide CO_2 emissions for all wind penetrations, by some 17, 70 and 85 kg-CO_{2e}/MWh for systems represented by the respective CAN, NWPP and US mixtures; this amounted to relative reductions of 13%, 32% and 17%, respectively.

From these results, it was possible to determine the costs of emission abatement by introducing wind power into existing systems of differing generation mixes. For a Canadian mix that relies quite heavily on hydropower, the cost of reducing CO_2 emissions is exorbitant because wind often substitutes for zero-emissions hydropower rather than coal. For a system similar to that represented by the US aggregate mix, with greater reliance on coal, the costs of reducing emissions is much lower, but still significant. The US mixture relies on all generating types. Wind will substitute for hydropower, natural gas and petroleum, and coal to some degree. There is inadequate hydropower for it to function fully as a storage device. In addition, because power plant efficiency is reduced, fuel costs are higher along with emissions intensity. A more optimal generating mix is represented by the NWPP. It has a greater hydro capacity, which can be used to store wind power when it is optimal to do so, while there is enough fast-ramp natural gas to militate against inefficient coal facilities. Thus, it would appear that only generating mixtures with the right balance between natural gas, coal (and nuclear) and hydro capacities can yield carbon abatement costs that are in a realistic trading range (< 100 \$/tonne-CO_2e).

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Figure Captions

Figure 1. Proportion of generation technology by capacity for each regional mixture.

Figure 2. Proportion of ramp rate constrained capacity in three levels of constriction for each regional mixture.

Figure 3. System operating cost as wind penetration grows for each regional mixture.

Figure 4. Average generator capacity factor as wind penetration grows for the CAN mixture.

Figure 5. Average generator capacity factor as wind penetration grows for the US mixture.

Figure 6. Breakdown of operating costs for the US mixture.

Figure 7. Average generator capacity factor as wind penetration grows for the NWPP mixture.

Figure 8. Energetic capacity factor for each of the nine time shifted wind profiles.

Figure 9. System operating cost for the US mixture for each of the nine time shifted wind profiles.

Figure 10. System operating emissions as wind penetration grows for each regional mixture.

Figure 11. The cost of abating emissions (marginal emissions cost) as wind penetration grows for each regional mixture.

Table 1: Generation mixtures for three simulated regions.

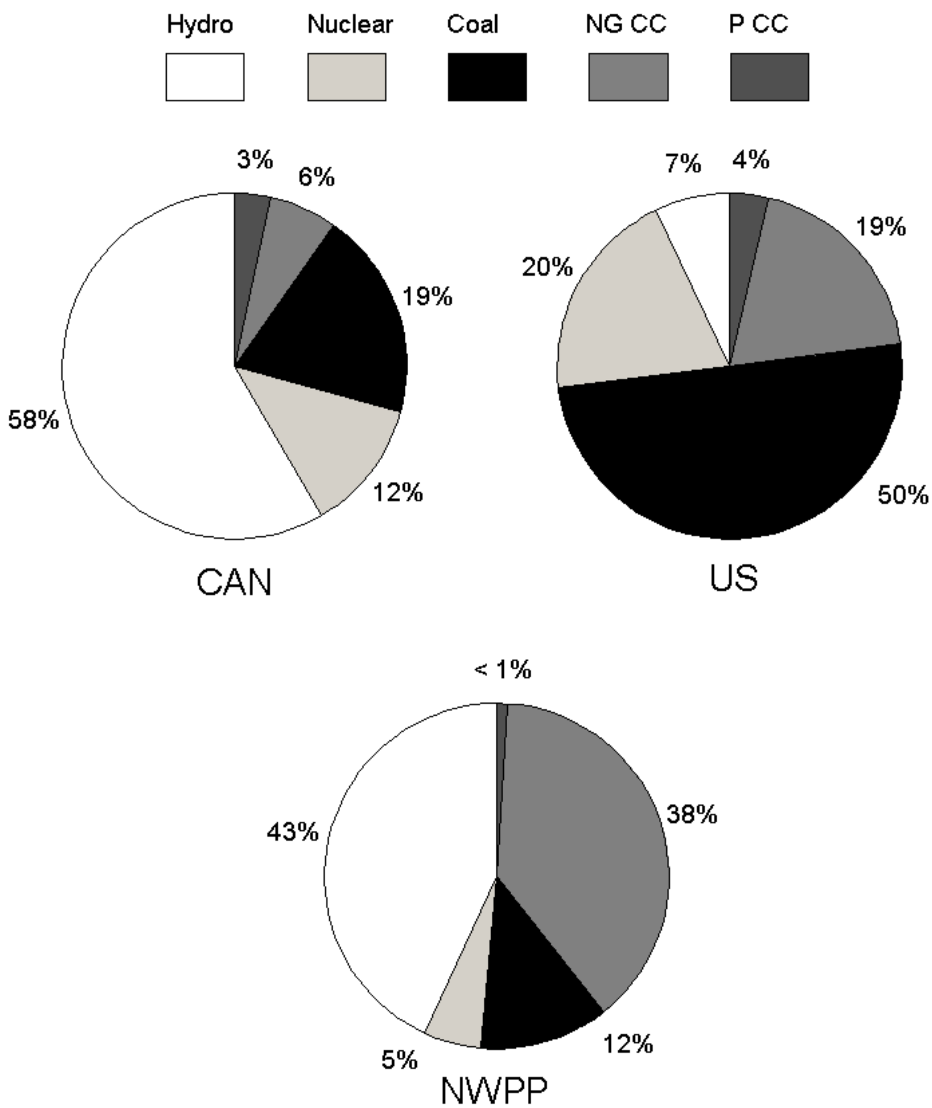
Generator	Generating Technology	Generator Capacity [MW]
Canada Aggregate		
1	Hydroelectric	900
2	Hydroelectric	300
3	NG[a] CC[b]	131
4	P[c] CC	70
5	Nuclear	255
6	Pulverized Coal	398
Total		2054
United States Aggregate		
1	Hydroelectric	145
2	NG CC	396
3	P CC	38
4	P CC	35
5	Nuclear	408
6	Pulverized Coal	1032
Total		2054
North West Power Pool		
1	Hydroelectric	485
2	Hydroelectric	400
3	NG CC	788
4	P CC	20
5	Nuclear	112
6	Pulverized Coal	249
Total		2054

[a] NG is an abbreviation for natural gas.
[b] CC is an abbreviation for combined cycle. The combined cycle technologies discussed in this paper refer to hydrocarbon-steam combined cycles.
[c] P is an abbreviation for petroleum.

Table 2: Fuel costs, and variable and fixed O&M costs, for various generation technologies (in CAD $).

Technology	Fuel Cost, (Af) [$/MWh]	Fuel Cost, (Bf) [$/MWh]	Variable O&M [$/MWh]	Fixed O&M [$/kW]
Hydroelectric	-0.04	1.13	3.64	14.47
NG CC	-76.50	150.90	2.14	12.93
P CC	-115.56	227.96	2.14	12.93
Nuclear	n/a	n/a	23.88	70.28
Pulverized Coal	-1.15	13.70	3.01	28.52
Wind	0.00	0.00	0	31.38

Figure 1



Hydro
Nuclear
Coal
NG CC
P CC
3%
6%
19%
58%
12%
CAN
7%
4%
19%
20%
50%
US
< 1%
38%
43%
12%
5%
NWPP

Figure 2

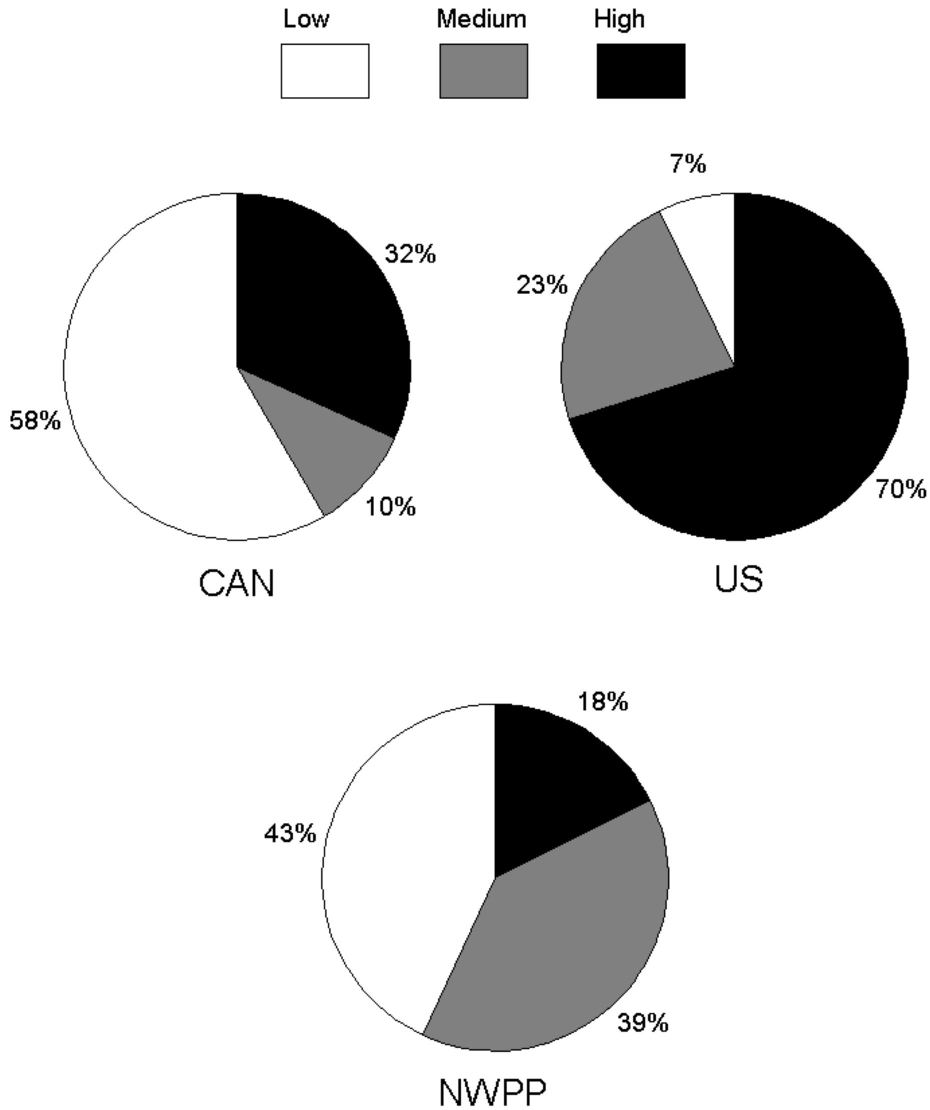
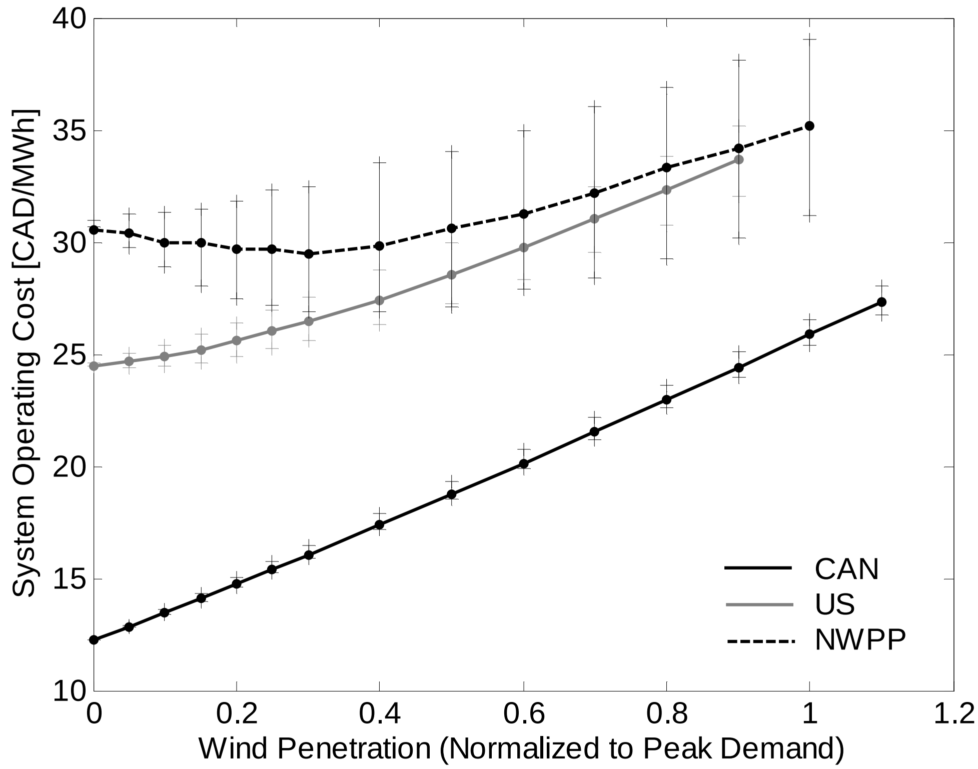
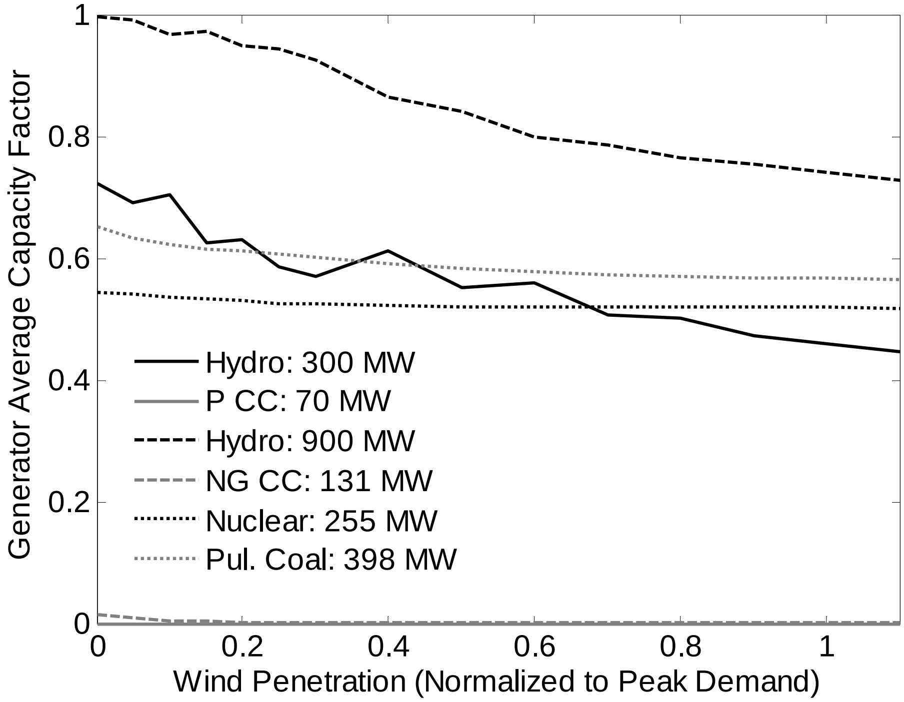


Figure 3



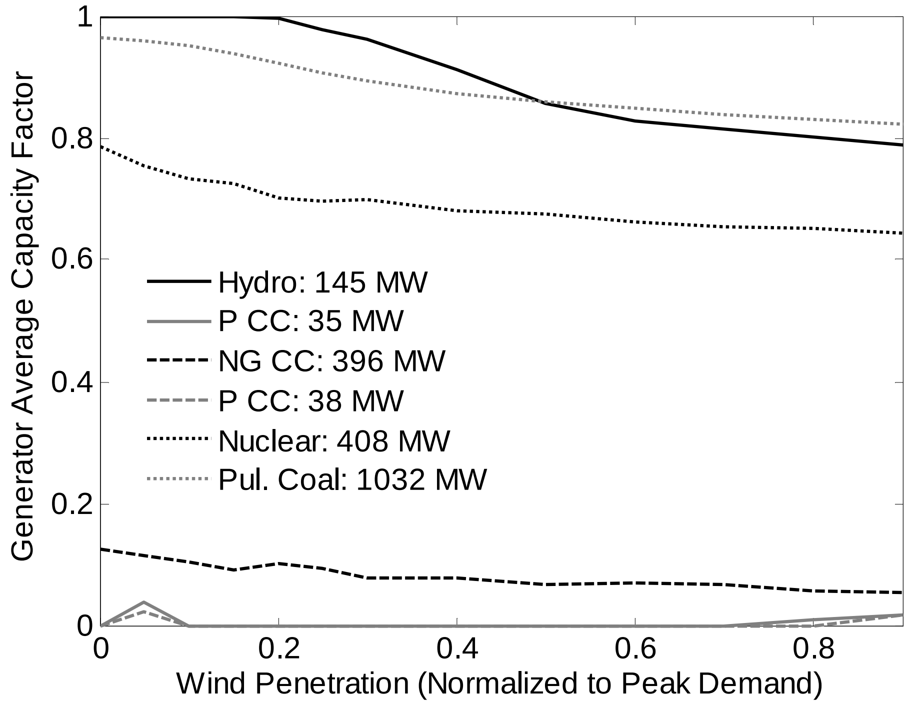
40
35
30
25
20
15
10
System Operating Cost [CAD/MWh]
0
0.2
0.4
0.6
0.8
1
1.2
Wind Penetration (Normalized to Peak Demand)
CAN
US
NWPP

Figure 4



1
0.8
0.6
0.4
0.2
0
Generator Average Capacity Factor
0
0.2
0.4
0.6
0.8
1
Wind Penetration (Normalized to Peak Demand)
Hydro: 300 MW
P CC: 70 MW
Hydro: 900 MW
NG CC: 131 MW
Nuclear: 255 MW
Pul. Coal: 398 MW

Figure 5



1
0.8
0.6
0.4
0.2
0
0
0.2
0.4
0.6
0.8
Generator Average Capacity Factor
Wind Penetration (Normalized to Peak Demand)
Hydro: 145 MW
P CC: 35 MW
NG CC: 396 MW
P CC: 38 MW
Nuclear: 408 MW
Pul. Coal: 1032 MW

Figure 6

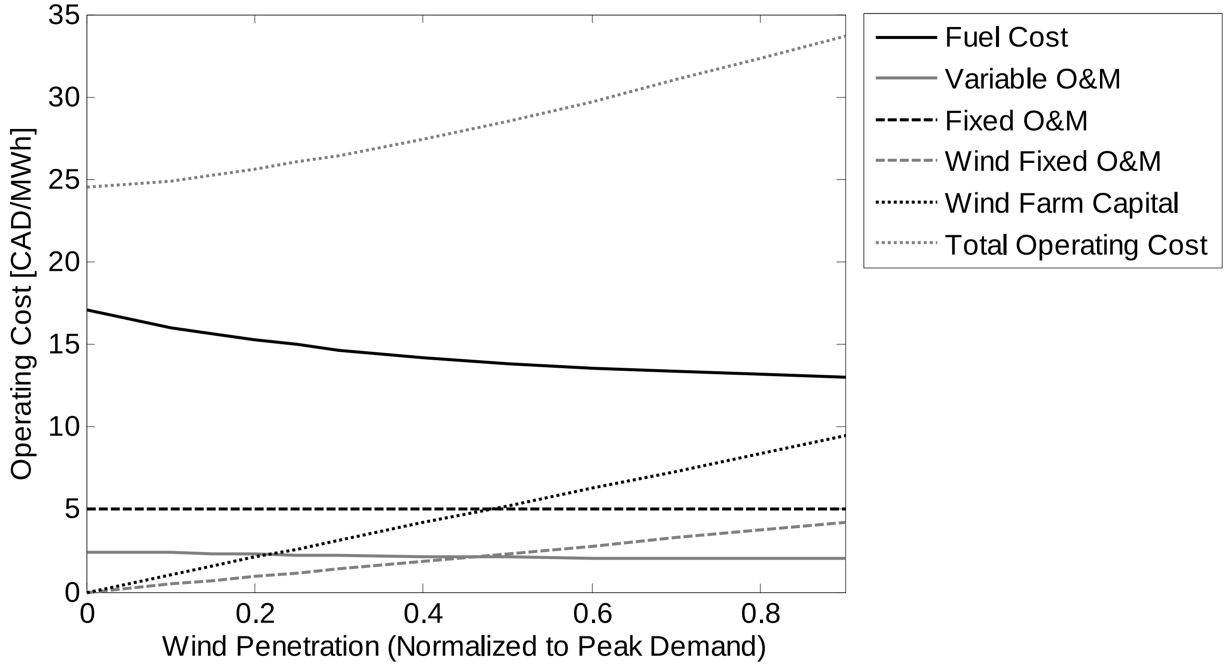
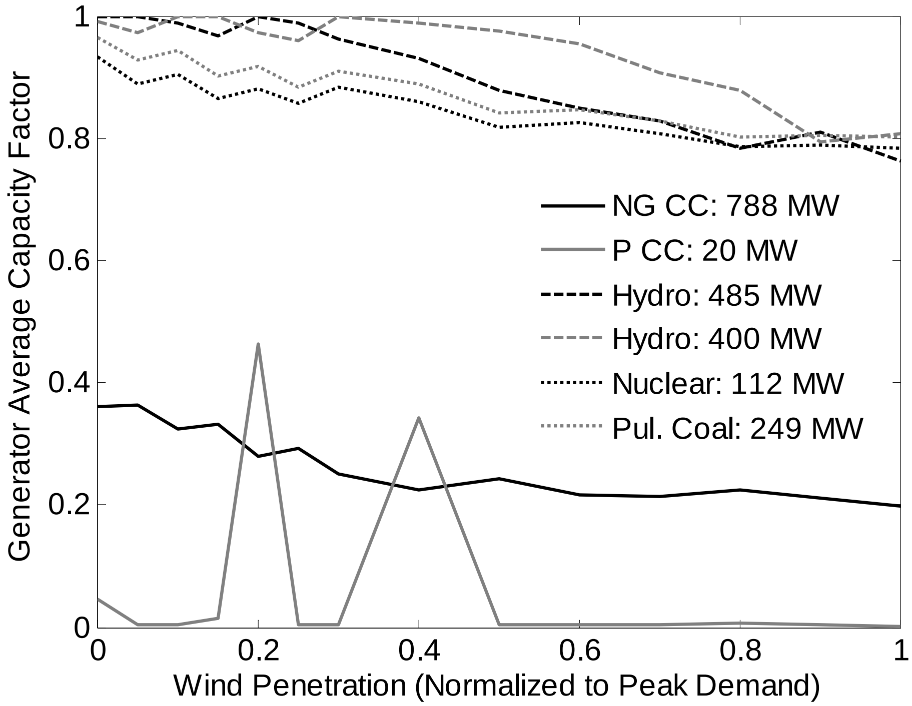
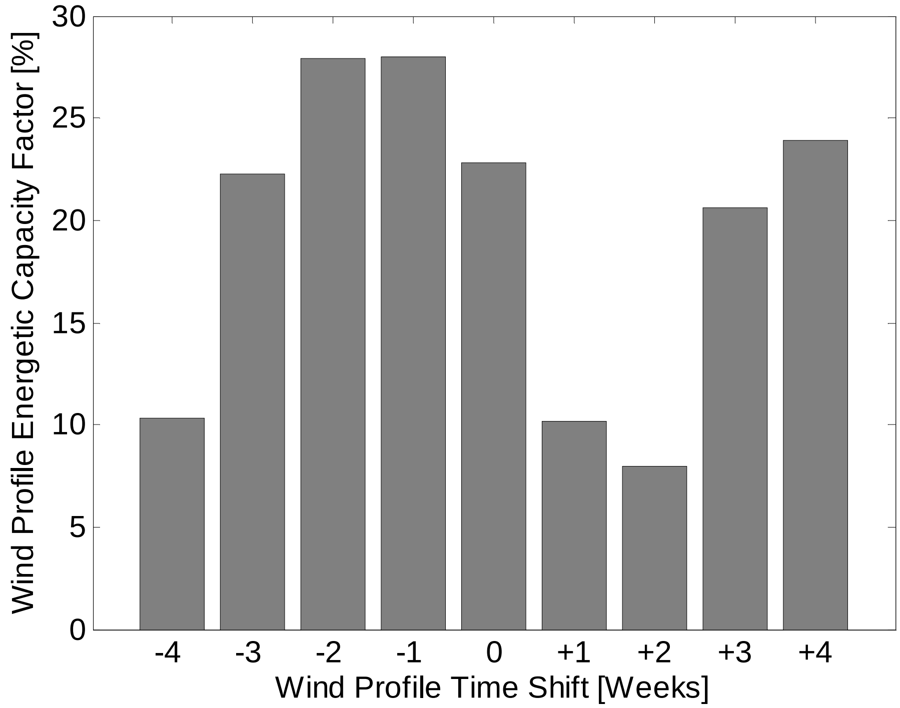

Fuel Cost
Variable O&M
Fixed O&M
Wind Fixed O&M
Wind Farm Capital
Total Operating Cost
Operating Cost [CAD/MWh]
Wind Penetration (Normalized to Peak Demand)
0
5
10
15
20
25
30
35
0
0.2
0.4
0.6
0.8

Figure 7



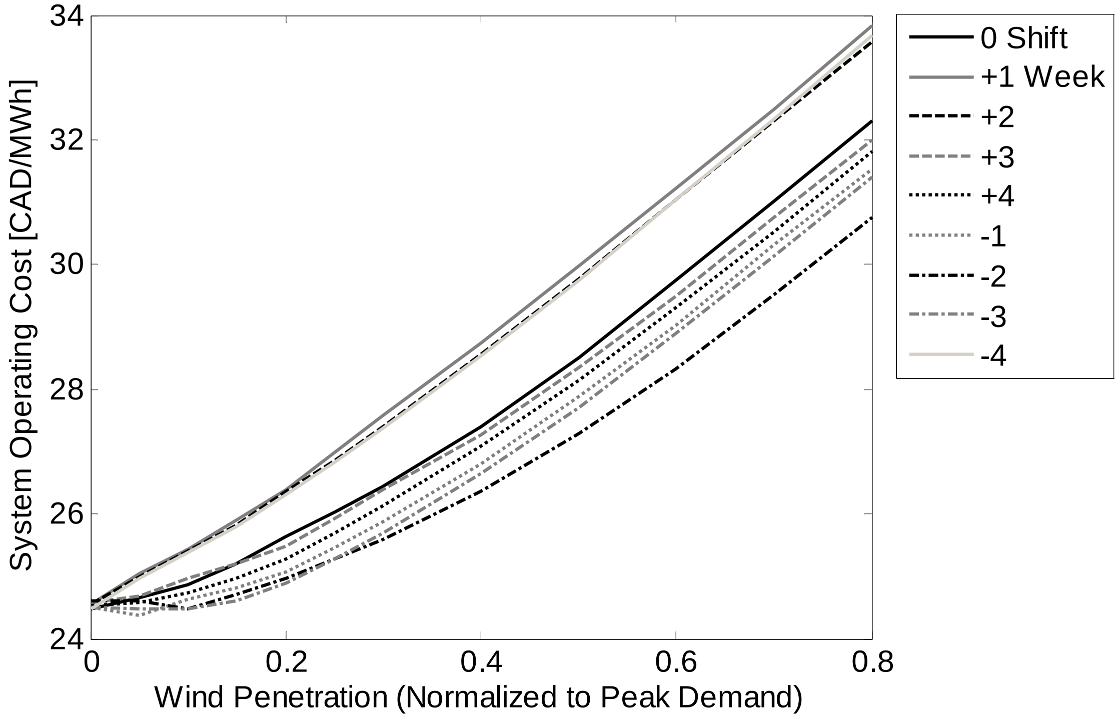
Generator Average Capacity Factor
Wind Penetration (Normalized to Peak Demand)
NG CC: 788 MW
P CC: 20 MW
Hydro: 485 MW
Hydro: 400 MW
Nuclear: 112 MW
Pul. Coal: 249 MW
0
0.2
0.4
0.6
0.8
1

Figure 8



Wind Profile Energetic Capacity Factor [%]
30
25
20
15
10
5
0
-4
-3
-2
-1
0
+1
+2
+3
+4
Wind Profile Time Shift [Weeks]

Figure 9



34
32
30
28
26
24
0
0.2
0.4
0.6
0.8
System Operating Cost [CAD/MWh]
Wind Penetration (Normalized to Peak Demand)
0 Shift
+1 Week
+2
+3
+4
-1
-2
-3
-4

Figure 10

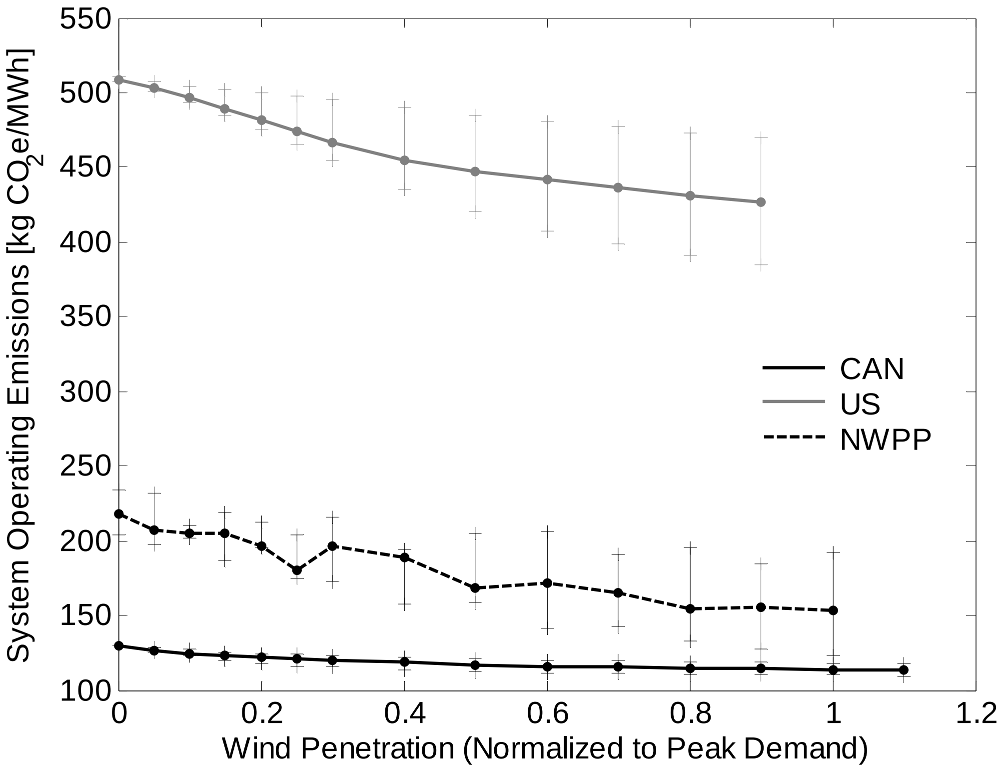
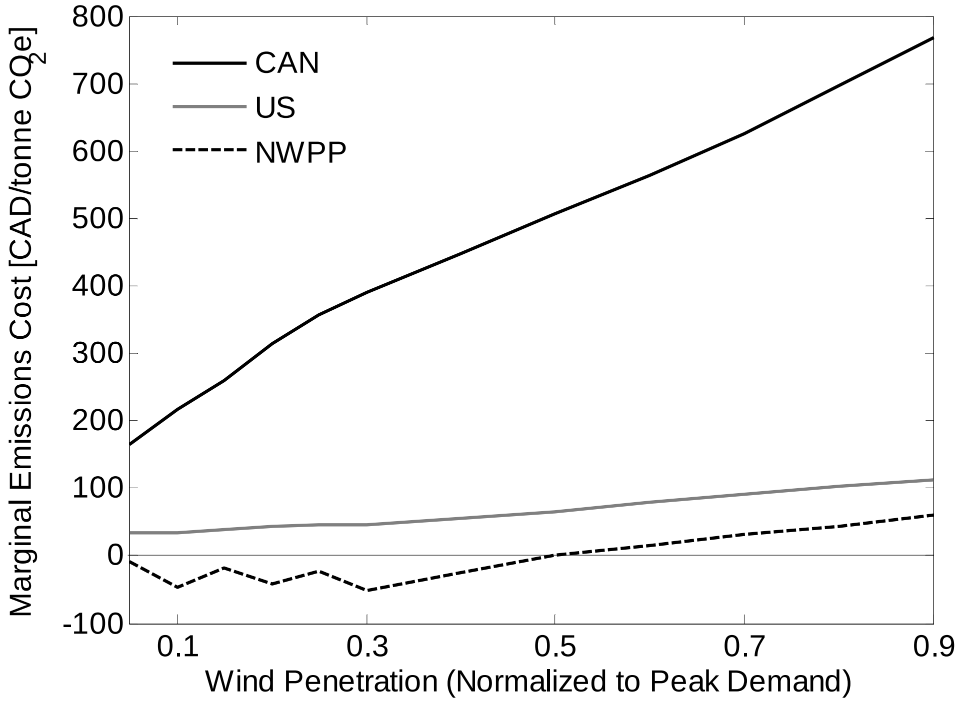

550
500
450
400
350
300
250
200
150
100
System Operating Emissions [kg CO_2e/MWh]
0
0.2
0.4
0.6
0.8
1
1.2
Wind Penetration (Normalized to Peak Demand)
CAN
US
NWPP

Figure 11



CAN
US
NWPP
Marginal Emissions Cost [CAD/tonne CO_2e]
800
700
600
500
400
300
200
100
0
-100
0.1
0.3
0.5
0.7
0.9
Wind Penetration (Normalized to Peak Demand)