Title	A quantitative analysis of the net benefits of grid integrated wind
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Publication date	2006-06
Publication information	Denny, Eleanor, Garth Bryans, John Fitz Gerald, and Mark O'Malley. "A Quantitative Analysis of the Net Benefits of Grid Integrated Wind." IEEE, 2006.
Conference details	Paper presented at the IEEE PES General Meeting 2006, Montreal, Quebec, Canada, 18-22 June 2006
Publisher	IEEE
Item record/more information	http://hdl.handle.net/10197/3301
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Publisher's version (DOI)	10.1109/PES.2006.1709459

A Quantitative Analysis of the Net Benefits of Grid Integrated Wind

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***Abstract*— Throughout the world significant development is being encouraged in wind energy for electricity generation. A complete cost and benefit analysis has been conducted in this paper on grid connected wind generation. It takes into account system costs such as reserve requirements, start-up and ramping implications for conventional plants as well as wear and tear costs. The benefits of wind generation analysed include the emissions benefits, the saving on the fuel bill, the electricity generated and the capacity value. These costs and benefits are then used to generate net benefit curves for wind generation and the sensitivities of the curves are tested with changes in the underlying assumptions. A complete unit commitment model with wind generation is used to determine the dispatches upon which the costs and benefits are calculated.**

***Index Terms*— Wind power generation, Costs, Power system economics, Power generation dispatch.**

I. Introduction

WIND generation penetrations are growing worldwide and there is much speculation on the impact of large levels of wind generation on electricity systems. This paper quantifies the costs and benefits of wind generation and investigates how different assumptions change the net benefits of wind generation. The approach adopted attempts to maximise social welfare and thus incorporates both direct and indirect costs and benefits into the analysis. Thus, it is assumed that society pays the capital cost for every MW installed of wind generation and reaps the benefits of every MWh of electricity produced from it. Any savings in the fuel bill are societal savings and any premature depreciation in the lifespan of a conventional generator from increased stresses is considered a societal cost.

An increase in variable generation on an electricity system may require the system operator to alter how conventional generation is dispatched since wind generation may receive priority dispatch [1]. As such, conventional generation may be obliged to operate at lower operating levels in order to be available to ramp up or down to accommodate the inherent variability of the wind generation. There may also be an increase in the number of start-ups and shut-downs of other units as system operators attempt to coordinate the following of the fluctuating load throughout the day and the variable output of the wind generation [2].

This work has been conducted in the Electricity Research Centre, University College Dublin which is supported by Electricity Supply Board (ESB) Networks, ESB Power Generation, ESB National Grid, Commission for Energy Regulation, Cylon, Airtricity and Enterprise Ireland.

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Thermal units are designed to be at their most efficient when online and running at a stable load. In general, units are optimised for continuous rather than cyclical operation and when operating in their normal range can operate for relatively long periods with relatively low risk and loss of equipment life [3]. As such, the frequent ramping of units and heating and cooling of the metals during start-up and shut-down can result in wear and tear on the machine and result in a shortening of the life span of the unit. In addition, the system operator will be required to carry additional reserve with growing levels of wind generation in order to maintain system security [4].

The societal benefits of wind generation analysed include the value of the electricity generated and the capacity value of wind generation. The indirect benefits investigated are the emissions savings and the reduction in the fuel bill resulting from a reduction in output of combustion plant on the system.

The results shown are based on the island of Ireland which has limited interconnection, low levels of installed hydro generation and a large and growing wind generation penetration. There is a relative generation capacity shortage in Ireland and temporary diesel generators are currently employed during periods of peak demand during the winter months [5]. This illustrates the need for additional capacity on the Irish system but also highlights the limitations of the system in responding to large fluctuations in wind generation production. Ireland is thus an ideal test system to investigate the system impacts of wind generation as the effects are relatively clear to identify and are not dampened by interconnection to other systems.

In compiling the costs and benefits a large number of assumptions are required and many of these are discussed and tested in this paper. The results are, however, limited by the necessity to constrain the scope of the study. The costs and benefits are evaluated based on a fixed plant mix and since the generation plant mix for 2010 is either already built or is currently under construction the assumed plant mix is for 2010 [5]. As the installed wind penetration grows significantly, the conventional plant mix is likely to evolve to include more flexible generation [6]. However, to analyse this temporal aspect would require a full analysis of the underlying electricity market, incentives and investment criteria, which is beyond the scope of this study.

Since this study aims to represent a social welfare analysis, the presence of an electricity market and the behaviour patterns of profit maximising generators are not explicitly included. In addition, it was necessary to omit 'softer' factors such as the visual impact of wind generation, the creation of jobs, improvements in local infrastructure, local environmental

impacts etc., in an attempt to limit the number of assumptions required.

Section II describes the model of the test system and the unit commitment algorithm used and Section III discusses the costs investigated. Section IV illustrates the benefits and the assumptions used to generate the benefit curves. The cost and benefits are brought together in Section V to show the net benefit curves for wind and a number of sensitivities are run. The results shown concentrate on the comparison of levels of influence of different assumptions rather than specific monetary values. The conclusions are given in Section VI.

II. Model of the Irish System

The conventional generation plant mix for this study is assumed to be fixed and represents the likely generation portfolio in the year 2010 [5]. Given the forecasted load profile for 2010, the generation plants are scheduled using the unit commitment and economic dispatch algorithm within the PLEXOS environment [7] for the entire year 2010. In the process of establishing a transparent market for the island of Ireland, the Irish system regulators gathered a data set of the detailed characteristics of all Irish generators [8]. This data set, referred to as the All-Island data set, contains all the necessary parameters to determine Equation 1, in addition to the energy required for the start-up of each plant from each stage of cooling [8]. The fuel energy required by each generator was determined using Equation 1.

$$E\left(P\right) = \beta P + \gamma \tag{1}$$

where
E(P) = Energy requirement for power output '*P*' (Joules).
β = Incremental heat rate (J/MWh)
P = Power output
γ = No load energy requirement (J)

In the analysis on the costs and the benefits in Sections III-V, three possible fuel price scenarios are investigated as shown in Table I [6].

TABLE I
Fuel Costs

Fuel	Low (€/GJ)	Mid (€/GJ)	High (€/GJ)
Gas	4.30	4.92	5.55
Coal	1.58	1.61	1.64
Oil	5.9	7.1	8.0
Peat	2.65	2.87	3.10

The operational constraints associated with the dispatch of a power system include both the thermal ratings of the transmission system components and the technical limitations of the individual generators. The transmission system was included within the model and solved using a DC load flow within PLEXOS, however, a number of simulations run over the month of January (period of maximum system load) demonstrated that generation was very rarely transmission constrained. Therefore, the transmission system was simplified to a single bus-bar system, and transmission system losses were ignored to enable better use of computational time in solving the commitment problem. Losses are highly dependent on the location of the generation on the network, and it is anticipated that future work by the authors will incorporate loss adjustment factors.

The generator constraints modelled include; minimum stable generation, maximum generation, maximum ramp-up rate, maximum ramp-down rate, minimum down-time, start time and scheduled outages. The problem was solved using the most rigourous method offered by PLEXOS (mixed integer solver), PLEXOS defines the problem and utilises a third party solver (MOSEK) to solve the problem.

The system reserve was optimised for each time step within the model based on the largest single in-feed to the system and an additional reserve requirement for wind generation which is dealt with further in Section III. In accordance with [1], the wind generation in the model was considered to have a marginal cost of zero which ensured it was always dispatched.

The interconnector from Scotland was assigned a predicted offer price for each trading period, based on historical records and the the hydro plants were assumed to have no fuel costs. The finite hydro resource and pumped storage plant were optimised to generate at periods of peak load and given the low penetration of hydro plant on the island of Ireland, and the requirement to use the pumped storage unit for system security these units were not used to provide reserve for wind generation.

III. Wind Generation Costs

Ireland currently has an installed capacity of approximately 600MW of wind generation and this figure is expected to grow significantly over the coming years [9]. The development costs as well as the system costs for wind generation are investigated in this Section. The results shown are for the 'mid' fuel price scenario detailed in Table I, however, the costs and benefits were generated using all three scenarios and the summary of results under each of the fuel price scenarios are given in Section V.

A. Wind Costs - Development

Assumed capital costs for wind generation were based on the three different cost curves shown in Figure 1. Costs were initially assumed to be €1 million per MW installed and in scenarios 2 and 3 the capital cost reduced incrementally due to likely advances in technology and turbine size. Scenario 1 is unlikely and is included for comparison purposes only. Under scenarios 2 and 3 it has been assumed that the most accessible and efficient sites are developed first. These are likely to be the largest wind farms with large economies of scale. As more and more wind generation is connected, the size of onshore wind farms is likely to decrease and feasible sites may become more inaccessible. For a smaller wind farm there will be diminished economies of scale and the cost per MW installed is likely to increase. In addition, it is likely that some of the growth in installed wind generation will come from offshore wind farms. Thus, through a combination of higher average cost per MW installed for smaller wind farms and an increase in more expensive offshore wind farms, the cost per MW installed at

high levels of installed wind capacity is assumed to increase beyond a certain installed level. This level was based on the forecasted feasible installed wind capacity on the island of Ireland, given in [10].

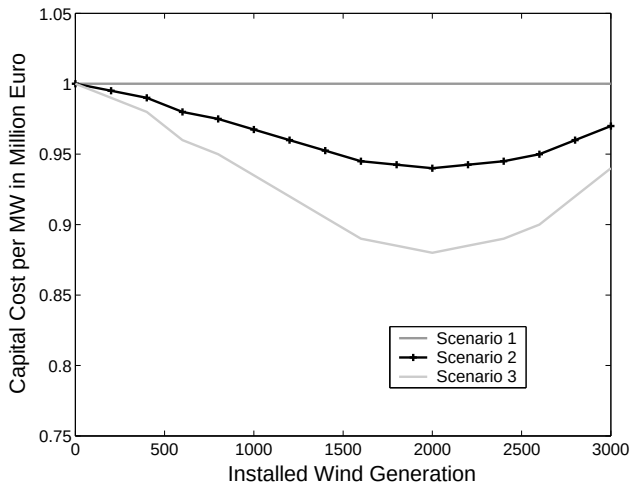

Fig. 1. Assumed capital cost per MW of installed wind generation

Throughout the study the costs are analysed on an annual basis, and in order to include the capital costs on an annual basis, the costs are assumed to be equivalent to an annuity where the cost of capital is assumed to be 10% with a term of 20 years. Operation and maintenance costs were assumed to be €35,000 per MW installed per annum [6].

B. Wind Costs - System

1) Reserve: The increase in reserve requirement with increasing installations of wind generation was based on [4] where the reserve target is derived by taking into account wind power forecast errors, load forecast errors, system reliability criteria and forced outage probabilities. Wind generation has little effect on the reserve categories that operate over a short time frame (seconds to minutes), but does impact on the requirement of reserve which reacts over longer periods (20min - 1 hour). The costs of reserve were based on [11] and are summarised in Table II.

TABLE II
OPERATING RESERVE COSTS

Reserve Category	Time Frame	Rate
Primary	5 - 15 sec	€1.80 / MWh
Secondary	15 - 90 sec	€1.63 / MWh
Tertiary 1	90 sec - 5 min	€1.49 / MWh
Tertiary 2	5 - 20 min	€1.49 / MWh
Replacement Reserve	20 min - 1 hour	€1.12 / MWh

Reserve costs are generated by multiplying the price from Table II by the required reserve in MWh. Figure 2 shows the system reserve requirements with increasing levels of installed wind (reproduced from [4]) with the cost curve for the year derived from Table II.

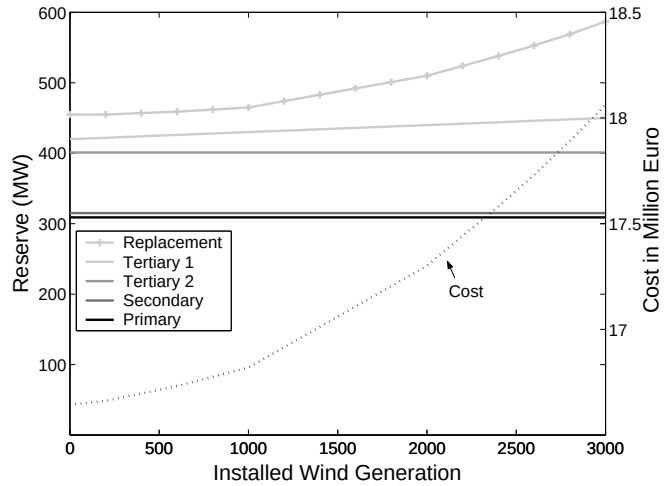

Fig. 2. Reserve requirements with increasing wind generation

2) Start-ups: In addition to reserve costs, the impact of wind generation on start-ups was analysed. Using the model described in Section II the number of start-ups for the resulting dispatches were calculated. For each dispatch the start-ups were divided into different classes - those of base loaded plants, mid-merit and peaking plants. Figure 3 shows the number of starts by the three categories of plants over the course of the year analysed.

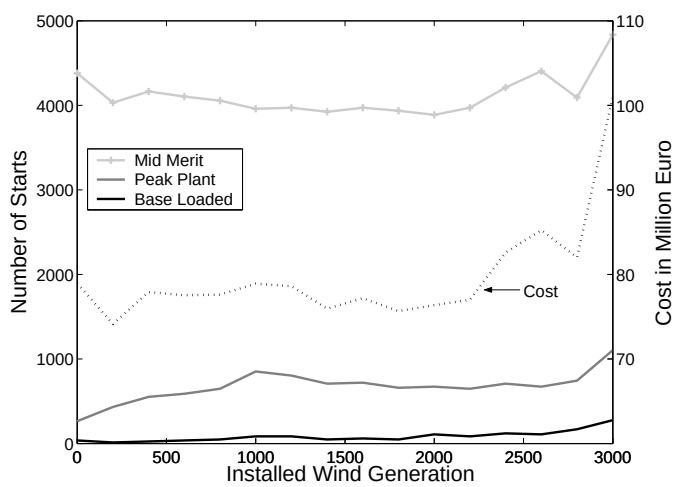

Fig. 3. Start-ups of conventional generation with increasing wind penetration

It can be seen that until the installed penetration of wind generation reaches approximately 2500MW, there is little effect on the number of starts for base-loaded plants, and in fact, there is a reduction in the number of starts of mid-merit plant. However, there is a significant increase in the number of starts for peaking plants. These plants are typically the most flexible on the system with the shortest start times and are among the cheapest plants to start and as such are more suited to dealing with short-term fluctuations in wind generation output.

The start-up costs were calculated for each of the three fuel scenarios based on the fuel costs for start-ups under the 'mid'

fuel price scenario plus a cost associated with the wear and tear of the machine for starting. The dashed line in Figure 3 shows the costs of the start-ups on the system for one year. It can be seen that the wind generation results in an initial reduction in start-up costs due to the switching from mid-merit starts-ups to peaking plant starts-ups with increased wind generation. However, it is clear that as soon as the number of starts of mid-merit plants and base loaded plants increase, the start-up costs increase significantly.

The wear and tear costs for starting a generator vary widely depending on the specific design of the generator. Certain types of generators are more suited to cycling than others and the wear and tear costs for these generators would be less than for a more rigid generator. For the purposes of this study a wear and tear cost for starting up is assumed to be €10,000 per start [12]. The impact of this assumption on the net benefit curve for wind is dealt with further in Section V.

3) Ramping: The ability to increase or reduce the output of an electricity generator is limited by the thermal and mechanical stresses imposed on the unit during the ramping process. The higher the change in output over a particular period of time, the more onerous the stresses imposed on the unit [3]. The model described in Section II commits the units and dispatches their hourly operating levels based on the specific ramp rates for each of the generators. Given the commitments and dispatches for each level of assumed wind generation, the number of periods of ramping and the extent of the ramping excursion was evaluated to determine the impact of wind generation on the ramping of the conventional units. The average excursion in output in MW for each generator class was calculated for the wind generation equal to zero and Figure 4 illustrates by how much the average MW excursion changes with increasing installed wind generation.

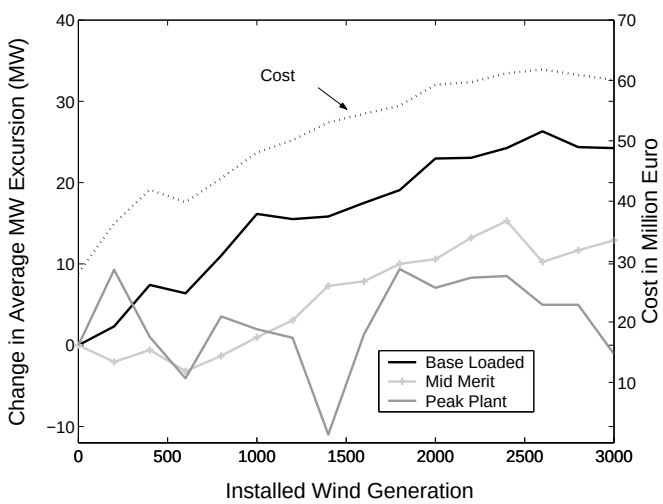

Fig. 4. Change in average hourly output over no wind case

A significant increase in ramping is seen for the base-loaded plants as wind generation increases. This has significant cost implications in terms of wear and tear on the units resulting in a decrease in the expected life-span of the unit. In addition, base loaded plants are generally the least flexible plants on the system compared to the fast-acting peaking plants. Thus, it is likely that the wear and tear costs for a base loaded plant would be higher than those of a peaking plant. For the purposes of this study, the wear and tear on a generator is considered to be €50 per MW change in output for a base loaded plant and €40 and €30 respectively for a mid-merit and peaking plant [12]. The implications of changing these wear and tear costs for the overall cost curves are given in Section V.

IV. Wind Generation Benefits

The benefit of the electrical output of wind generation is analysed in this Section. The indirect benefits investigated are the emissions benefits from the reduction in output of conventional plants and the saving in the national fuel bill.

A. Electrical Output

The primary purpose behind building a wind turbine is to generate electricity, this electricity is then traded in an electricity market and the market determines a price at which the electricity is sold. However, this market price does not necessarily represent the 'value' of electricity as clearly indicated by the situation when negative prices occurs. The value of electricity as a whole could be deemed to be equal to the cost associated with not having it, i.e. the cost of lost load. However, this value is considered to be excessively high to measure the value of the MWhs from an individual unit, as the loss of those MWhs would not necessarily result in load shedding.

For the purposes of this study, the value of the electricity produced from wind generation is deemed to be a combination of the saving from not having to use a conventional unit to generate the electricity and the benefit for system security of an increase in installed capacity. Based on [13] and [14] the value of electricity is assumed to be €40/MWh.

The electricity output of a wind generator is based on its load factor. The load factors for wind generation in Ireland are assumed to range from 25% - 40% depending on a large range of factors including location, turbine size, season etc. [15]. It is assumed that the most favourable sites for wind turbines will be developed first and these are likely to have the highest load factor. For this reason it is assumed that the load factor per MW installed decreases with increasing installed capacity. Capacity factors for wind generation on the system are assumed to be equivalent to those in [6]. In Figure 5 a 'production factor' (PF) is used to represent the load and capacity value of wind generation. Since the value of electricity assumed in this paper includes the capacity value per MW installed, the production factor is multiplied by €40/MWh to give the benefit of electricity from wind generation per annum.

It is clear from Figure 5 that the assumed production factor has a significant impact on the shape of the benefit curve. The impact of changing the value of electricity from €40/MWh is investigated further in Section V.

B. Emissions Benefits

As the installed capacity of wind generation increases it displaces conventional generation which has an impact on

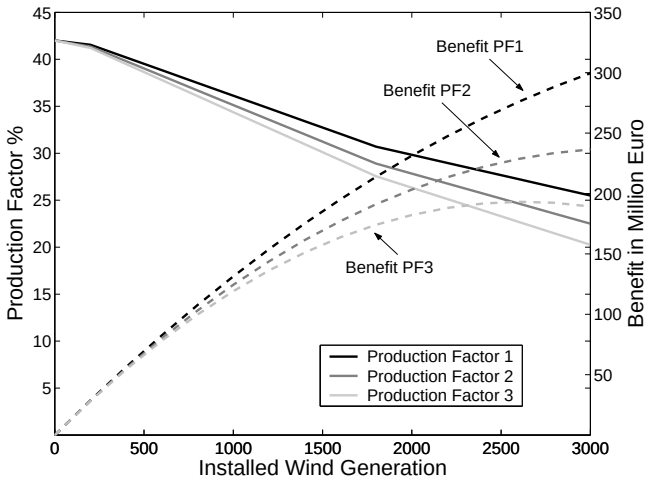

Fig. 5. Three different scenarios for assumed production factor

the emissions from the conventional units. Using the plant operating schedules attained from the model described in Section II, the resulting hourly CO_2, SO_2 and NO_x emissions from the conventional units are calculated by using specific emissions information for each generator from [9] and [16].

Emissions of CO_2 and SO_2 depend on the quantity of fuel burnt and the carbon and sulphur content of the fuel respectively. So a reduction in the output of a thermal unit will cause a reduction in CO_2 and SO_2 emissions. Natural gas contains a negligible quantity of sulphur, thus, SO_2 emissions are not an issue for gas turbines [16].

NO_x emissions do not solely depend on the amount of nitrogen in the fuel but also on other factors such as the fuel temperature, the oxygen concentration, the residence time etc. Of particular interest are the NO_x emissions characteristics of combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) where lean premixed combustion is a standard technique. This premix (of fuel and air) achieves low levels of NO_x emissions without the need for additional emissions reduction hardware such as selective catalytic reduction. However, due to combustion instabilities this premixing is not possible below 70% of operating capacity for a CCGT and 65% for an OCGT. As a result, NO_x emissions in a CCGT and an OCGT can treble at lower loads [16].

For the purposes of this study, it was assumed that the CO_2 and SO_2 values did not change significantly during ramping. However, due to the increased O_2 levels present during ramping, a 10% increase over steady state conditions was applied at various loads to capture the potential NO_x increases during periods of significant ramping [16]. Since IPPC legislation [17] does not account for emissions of SO_2 and NO_x during start-up, only start-up emissions of CO_2 were considered. In addition, emissions were based on electricity 'generated' rather than 'exported' for each generator [18].

Figure 6 illustrates the emissions benefits from increasing levels of wind generation for CO_2, SO_2 and NO_x. The magnitude of CO_2 emissions is much larger than for the other two emissions, however, for ease of illustration all three emissions have been plotted on the same axis in Figure 6. The CO_2 emissions, usually quoted in millions of tons, have been divided by 1000 in order to plot them on the 'Emissions in kilotons' axis.

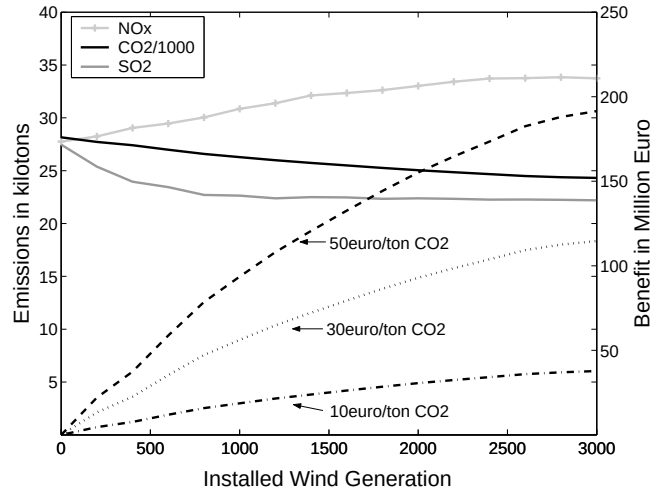

Fig. 6. Emissions benefit of increasing wind penetration assuming various CO_2 prices with constant SO_2 and NO_x prices

These emissions results vary from those given in [16] as the underlying dispatch model is different. In [16] a simple two-step linear optimisation programme was used to determine the dispatch and it was unable to consider temporal constraints. However, as described in Section II, the model used for this paper is a full unit commitment model which incorporates ramping constraints, minimum up and down constraints, start-up times etc. These temporal constraints have a significant impact on the resulting emissions.

The CO_2 emissions reduce incrementally with increasing wind generation since as conventional plant is displaced, typically less fuel is burnt. In [16] the model assumes peat generation as a must-run generator, however, for this study the peat generation was required to participate in the unit commitment dispatch model like all other thermal generators. This factor along with a reduction in the output of oil-fired generators contribute to the reduction in SO_2 emissions with increasing wind generation.

The most surprising element which was not seen using the simple model in [16] is the *increase* in NO_x emissions with increasing wind generation. This is mainly due to the NO_x emissions characteristics of gas turbines as described above. As the wind generation increases, the operation of gas fired plants below 70% occurs more frequently. In addition, as evident from Figure 3 there is an increased reliance on peaking plants with increasing wind generation and these plants are mainly OCGT plants with a small number of distillate generators which have significant NO_x emissions. Also since the NO_x emissions during ramping were included, the results shown in Figure 4 contribute to the increase in NO_x emissions.

The secondary y-axis in Figure 6 illustrates the benefits in millions of euro of the saving in emissions for three different CO_2 prices of €10, €30 and €50 per ton. The difference between the three benefit curves show how sensitive the

benefits of wind generation are to the price of CO_2.

Since there is not currently an emissions market for SO_2 and NO_x in Europe, the emissions costs are nominally assumed to be €150 per ton of SO_2 and €250 for NO_x. The impact on net benefits of changing the prices of SO_2 and NO_x is investigated further in Section V.

C. Fuel Bill

As wind generation displaces electricity produced from thermal units the quantity of fuel burnt by the thermal units changes. Figure 7 illustrates the annual fuel consumption in petajoules for each fuel type on the Irish system and how the consumption changes with increasing wind generation. The additional fuel burnt during start-ups is also included in the fuel use.

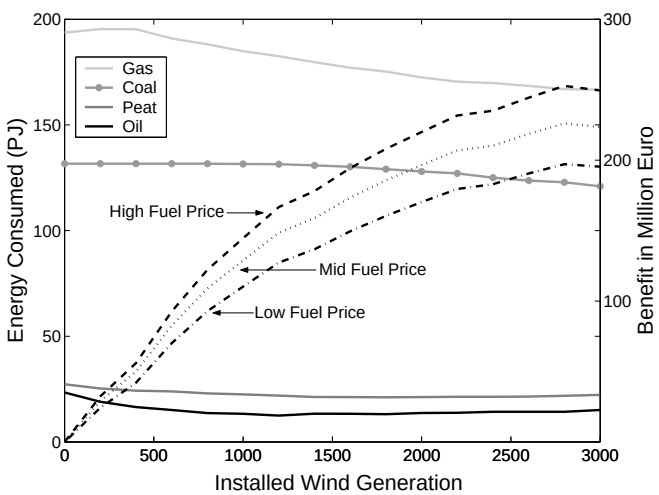

Fig. 7. Fuel use with increasing wind generation

Figure 7 shows that the main reduction in fuel use is for gas fired plants. The benefits over a wind energy penetration of zero on the secondary y-axis are based on the saving in purchase of fuel and are based on the 'mid' fuel price scenario given in Section III.

V. Results

The purpose of doing a detailed investigation of costs and benefits of wind generation is to inform policy makers as to the appropriate quantity of wind generation to promote. The curves described in Sections III and IV show the relationship between increasing wind generation and the costs and benefits and it is these relationships which are evaluated further in this Section rather than the absolute monetary values of the net benefits. The cost and benefit curves shown above were summed into a single cost function and a single benefit function for each level of installed wind generation under a range of scenarios. The figures that follow show how the net benefit curve changes with modifications in the underlying assumptions. In each figure, the base case curve (given by the black line with + markers) represents the assumptions given in Table III:

TABLE III
Base Case Assumptions

Assumption	Scenario
Capital Costs	Scenario 2
Fuel Price	Mid
Wear and Tear for starts	€10,000 per start
Ramping	€50, €40, €30/MW
Electricity Value	€40/MWh
Production Factor	PF Scenario 2
CO_2 price	€30/ton
SO_2 price	€150/ton
NO_x price	€250/ton

A. Fuel Price Sensitivities

Figure 8 shows how changes in fuel price assumptions affect the net benefits curve. The 'mid' fuel price scenario is the base case as described in Table III.

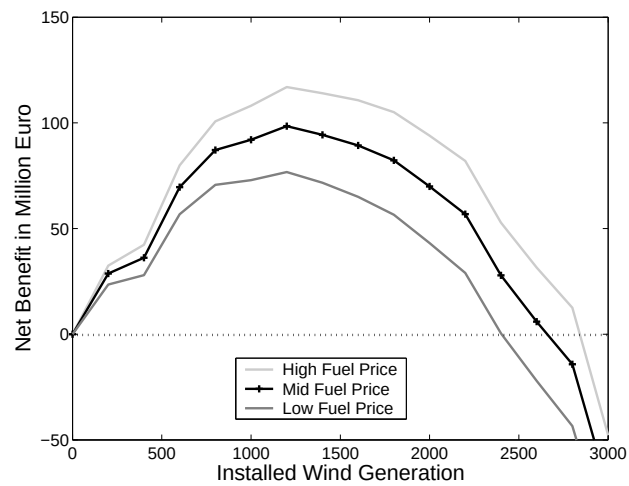

Fig. 8. Net benefits of wind generation with three fuel price scenarios

From Figure 8 it is clear that the net benefits curve rises initially with increasing installed wind generation and then falls as the difference between the benefits and the costs reduces. Using the assumptions from Table III the costs of wind generation begin to exceed the benefits when the installed capacity reaches approximately 2600MW. When the 'high' fuel price is assumed, the net benefit curve shifts upwards and the point where the curve crosses the x-axis moves to the right.

B. Carbon Dioxide Price Sensitivities

Figure 9 illustrates how the net benefits vary with changes in the price of carbon. Not only does the curve shift upwards with the increase in carbon price, it also shifts to the right indicating that the point of maximum net benefit will be at a higher penetration of wind generation. Also, the point where the curve crosses the x-axis will move to the right, indicating the wind generation penetration where costs exceed benefits will be at a higher level than under lower carbon scenarios. For each of the curves in Figure 9, the price of SO_2 and NO_x are fixed (from Table III).

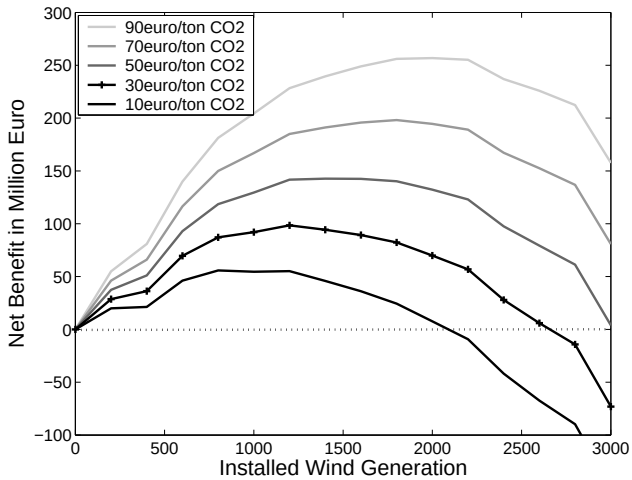

Fig. 9. Net benefits of wind generation with different CO_2 different prices

C. Sulphur Dioxide and Nitrogen Oxides Price Sensitivities

Figure 10 illustrates how the net benefits vary with changes in the price of SO_2 and NO_x. For all curves in Figure 10 the price of carbon is assumed to be €30 per ton.

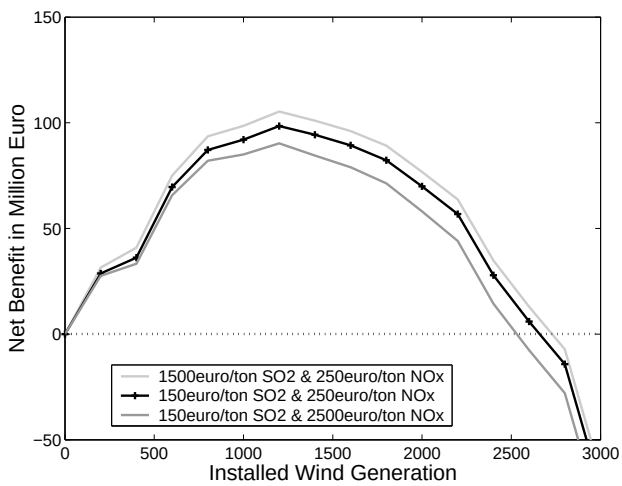

Fig. 10. Net benefits of wind generation with different SO_2 and NO_x prices

It can be seen that even a ten-fold increase in the price of SO_2 to €1500 per ton has little impact on the net benefits curve. When the price of NO_x increases by a factor of ten to €2500 there is a slight reduction in the net benefits curve due to increasing levels of wind generation causing an increase in NO_x emissions (as discussed in Section IV). However, this graph clearly indicates that even were the price of NO_x to be very high, the impact of wind generation on the cost of NO_x emissions is relatively small.

D. Production Factor Sensitivities

Figure 11 illustrates how the net benefits vary with the three production factor curves from Figure 5. The shape of the production factor curve determines the MWhs of electricity generated from wind generation so a lower production factor will result in less conventional generation being displaced which has a direct knock-on effect on the costs and benefits. A higher assumed production factor shifts the net benefits curve upwards and to the right. From Figure 11 it is clear that the assumed production factor has a significant impact on the results.

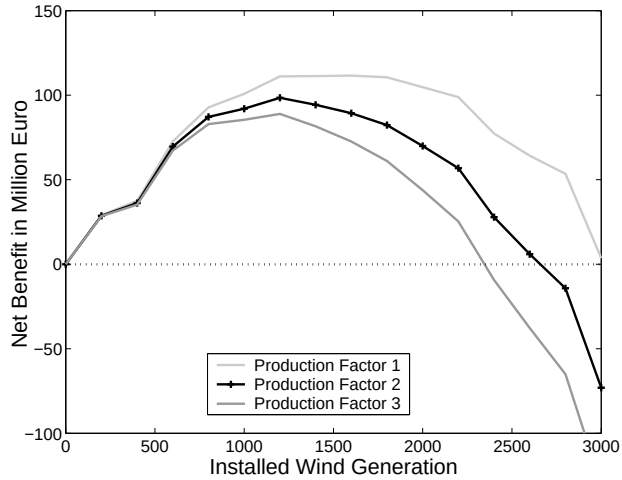

Fig. 11. Net benefits of wind generation with the different load factor curves

E. Electricity Value Sensitivities

Section IV placed a value on electricity of €40/MWh and this value was used in the base case analysis. Figure 12 shows how the net benefits curve changes when this electricity value is altered. It is clear that the net benefit of wind generation is highly dependent on the assumed value of electricity and as this value is increased the curve shifts upwards and to the right. With a low assumed electricity value of €20/MWh, the costs exceed the benefits at a much lower installed capacity, of approximately 1650MW.

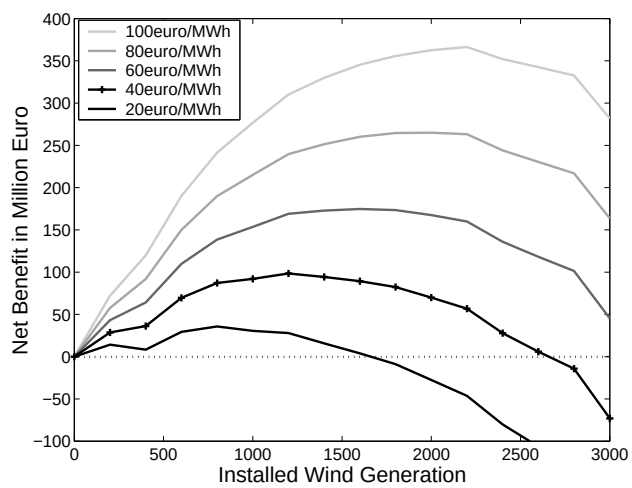

Fig. 12. Net benefit curves for different electricity values

F. Start and Ramping Cost Sensitivities

Figure 13 illustrates how the net benefits curve changes with changes in the cost of the stresses on the conventional units. The base case assumes a start-up cost of €10,000 per start and

Figure 13 illustrates that the net benefits curve does not change significantly if this cost is increased to €30,000. However, it is clear that if ramping costs are increased from the base case of €50, €40 and €30 per MW change for a base-loaded, mid-merit plant and peaking plant respectively to €150, €120 and €90 there is a significant reduction in the net benefits curve for wind generation.

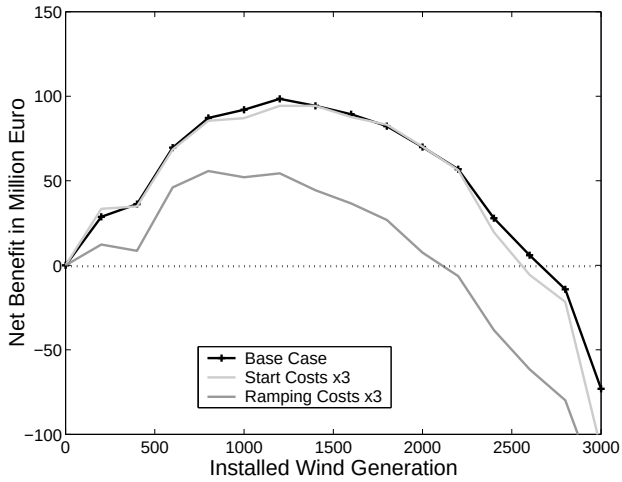

Fig. 13. Net benefit with increased start-up and ramping costs

G. Other Cost and Benefit Sensitivities

The effect on the net benefits curve of changing the assumed capital costs to scenario 1 from Figure 1 shifts the peak in the curve downwards by approximately 6%. Capital cost scenario 3 shifts the peak upwards by 6% over the base case. The effect of changing the assumed cost of capital from 10% to 12% moves the net benefit curve downwards with a reduction in maximum net benefit of approximately €32m.

VI. Conclusions

The results shown in this paper are based on a full unit commitment dispatch for an entire year for the island of Ireland. Ireland is an ideal test system to investigate the system cost of wind generation and provides a prediction of the likely effects of large penetrations of wind generation on other electricity systems. The results are limited by the necessity to constrain the number of assumptions included and as such the focus of the paper is on the sensitivity of the net benefits curve to changes in assumptions rather than the absolute value of the net benefits. The results show that for relatively low levels of installed wind generation the system start-up costs are relatively constant, however, the average ramping excursion increases in size with increased wind. It was found that the net benefits of wind generation are highly sensitive to the assumed fuel price, the price of carbon, the cost of ramping, the production factor and the assumed value of electricity and capacity. The net benefits of wind generation are not particularly sensitive to the price of SO_2 and NO_x emissions, the start-up costs or moderate changes in the capital costs for wind generation.

Acknowledgment

The author gratefully acknowledge the contributions from the Irish electricity industry, in particular Michael Kelly, Michael O'Mahony and Dermot O'Kane.

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