Quantifying CO_2 savings from wind power: Ireland

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Abstract

The contribution of wind power generation to operational CO_2 savings is investigated for the Irish electricity grid. Wind contributed 17% of electricity demand in 2011 and reduced CO_2 emissions by 9%. Wind energy saved 0.28 tCO_2/MWh on average, relative to a grid carbon intensity in the absence of wind of $0.53tCO_2/MWh$. Emissions savings are at the lower end of expectations. It is likely that this reflects decreasing effectiveness of wind power as wind penetration increases.

1 Outline of the problem

Increase in atmospheric greenhouse gases, due mainly to burning of hydrocarbons and coal, is shifting the Earth's radiative balance in favour of a warmer climate.[1] Reduction of industrial CO_2 emissions is a major focus of global environmental policy. One widely adopted policy measure are state supports for wind power[2] on the grounds that wind power displaces fossil fuel generation and so reduces emissions. State supports have included mandatory targets, feed-in tariffs, subsidised finance for infrastructure etc. As a consequence, significant amounts of wind power have been embedded into electrothermal generation systems. It has been known for some time that thermal generation responds in a non-trivial way when operated in parallel to stochastic power sources to meet system demand. Not all thermal plant are displaced equally, with flexible and/or high marginal cost generation being displaced the most. Average efficiency is reduced and higher cycling rates occur than would otherwise be the case. All of these effects tend to reduce the effectiveness of wind power in meeting it's primary policy goal, namely emissions reduction.

The task of quantifying emissions savings from wind power is not straightforward. Electricity grids are complex systems, with many competing components and feedbacks. Moreover every grid has a different combination of fuel-mix, generator types, wind penetration, interconnection, despatch practices etc. Estimates of emissions savings have ranged widely[3] from higher than grid average[4, 5] to near zero[6, 7]. Savings assumptions by public authorities have trended lower over time.[8] Meanwhile despatch models have demonstrated that marginal savings decrease as installed wind capacity increases[9, 10] and that high levels of wind penetration may even be counterproductive in terms of emissions.[11]

Empirical approaches based on real world grid data can help shed further light on these issues. Ireland is a good empirical test case for the following reasons:

1. high average wind penetration (17% in 2011)
2. minimal electricity exports means that virtually all wind generation must be accommodated on the domestic grid
3. modern thermal plant portfolio with large amounts of relatively flexible gas generation ($\approx 58\%$ of demand) as well as coal and peat plant
4. zero nuclear and a low level of hydro ($\approx 2\%$)
5. Ireland's highly volatile wind resource favours statistical even over relatively short timeframes such as one year
6. availability of relatively high frequency grid data and mandatory emissions reporting at plant level under EU-ETS.[12]

The Irish grid operator[13] reports approximate system demand, wind generation and total CO_2 emissions rate every $\frac{1}{4}$-hour. It is easy to obtain a preliminary estimate of emissions savings from this dataset. Linear regression of the time-series of grid carbon intensity (emissions rate per unit demand) onto wind penetration (wind generation per unit demand) gives a zero-wind emissions intensity of $0.51tCO_2/MWh$ and wind power savings $0.35tCO_2/MWh$ in 2011. This is equivalent to a displacement effectiveness of just 65%. A plausible interpretation is that wind power displaces primarily clean gas (which have typical emissions $\approx 0.35tCO_2/MWh$) rather than high emissions coal or peat.

While these numbers are suggestive, their origin and accuracy are unclear. Firstly, aggregate numbers cannot show which generators or fuels are being displaced by wind power. Secondly, cycling effects (startup and ramping of thermal plant) are not included in the carbon emissions algorithm used by the grid operator. Thirdly, the role played by interconnection (electricity imports and exports) is unclear. Fourthly, the result for emissions savings is sensitive to the correlation between wind generation and system demand. Spurious correlation may be present because approximate wind generation is used in the calculation of system demand.

In this study, time-series of CO_2 emissions are estimated for each grid-connected thermal unit in 2011. This calculation is based on generation data and physical characteristics of each generator. Additional emissions due to start-ups are included. Based on this CO_2 data, and a careful treatment of the wind and system demand, we estimate wind savings of $-0.28tCO_2/MWh$ with implied effectiveness of only 53%. Some implications of these numbers are discussed at the end of the article.

2 Data and model

Data on the Irish electricity grid is available from a number of sources.[13],[14],[15] The *Single Electricity Market Operator* (SEMO) provide $\frac{1}{2}$-hourly generation data. "Ex Post Initial" metered generation data is compiled four days after generation date for invoicing purposes. This accurate dataset is used here. SEMO provide a loss factor adjusted total metered generation ("MGLF") time-series which includes all domestic generation as well as power traded via interconnectors to Northern Ireland. Each power source is weighted by a unit specific transmission system loss factor which also depends on time of day and season. MGLF is a proxy for total end-user demand because accurate balance between generation and demand is required at all times in order to maintain grid frequency stability. MGLF is very similar but not identical to the real-time system demand recorded by the grid operator (correlation 0.99).[13] A time-series of net intra-jurisdiction imports/exports is also available ("NIJI").

Under the priority despatch rule for wind, conventional generation must adjust continuously to match system demand minus wind generation. From the point of view of the conventional generation system, wind generation is an exogenous random variable which reduces effective demand but also makes it more volatile, Figure 1. The aim is to find out what impact this has on individual thermal generators. SEMO provides $\frac{1}{2}$-hourly metered generation data ("MG") data on all grid-connected generators.[15]. Excluding wind power, 54 generators supply the Irish grid. 35 of these are thermal, the rest are small hydro/pumped storage units. Descriptions of thermal generators such as fuel type, maximum capacity etc are given in Table 3.[15]

Wind generation is the sum of the outputs of more than 130 wind farms. Most of these are smaller installations connected to the distribution system. SEMO also provide $\frac{1}{2}$-hourly MG data for wind farms but there are gaps in this dataset. Some kind of statistical modelling is required to recover total wind generation. To do this, generation data for 36 of the largest wind farms which were fully operational during 2011 (20 transmission and 16 distribution system connected) were compiled. The sum of the capacities of this sample amounted to $\approx \frac{2}{3}$ of the total installed wind capacity during 2011. The time-series of total output from the sample was normalised upwards to reflect the correct total installed monthly wind capacity (this allows for $\approx$ 200MW increase in wind capacity during 2011). This is expected to be a good approximation, because wind generation is highly correlated in space and in time.[1] The estimate of wind generation resulting from the procedure is similar to the real-time estimate of the grid operator (correlation $\gtrsim 0.99$).[13].

In all, the generator dataset used in this study contains close to 2 million data points. A visualisation of the dataset showing $\frac{1}{2}$-hourly generation fraction

[1] The physical reason for this is that the maximum linear separation of wind farms on the Irish grid is much less that the extent of typical mid-latitude weather systems which bring windy or calm conditions. For example the correlation between wind generation at Meentycat in extreme North-West and Carnsore in the extreme South-East is 0.47. Autocorrelation is also very strong e.g. 12 hour lagged correlation is 0.65

by fuel type ("fuel-mix plot") is shown in 2 [17]. Gas is the dominant power source (53%) and it is displaced when wind generation is present.

To model CO_2 emissions, detailed physical characteristics of individual thermal generators are required. Parameters listed in Tables 3,4 are used by electricity market participants to determine fuel use and support despatch decisions.[16] Table 4 gives *Incremental Heat Rate Slopes* (GJ/MWh) which are defined between a set of capacity points (MW) specific to each generator. Together with zero-load energy use (GJ/h), these can be inverted to find the rate of energy use by the generator at each capacity point. Full input-output curves were then constructed by cubic spline interpolation. These input-output curves give the emissions rate when a generator is operated in steady state at any point between 0MW and MaxCap (making use of fuel CO_2 emission factors[14]). In practice generators can only operate in steady state only between *MinCap* and *MaxCap* or as spinning reserve (at 0MW).

Once input-output curves have been constructed, they can be combined with generation data to create emissions time-series for each unit.[2] Total emissions calculated in this way include the effects of generation mix and part-load efficiency. Emissions from this model were 11.64Mt in 2011, compared to 11.67Mt using the grid operator data.[13] The two emissions time-series are similar but not identical with a correlation of ≈ 0.97. Further tests on the validity of this model are described below.

Additional emissions arising from cycling (start-ups) can be calculated using parameters in Table 3. Fuel costs (in GJ) depend on thermal state of the generator at start-up (Hot, Warm or Cold). With appropriate initial conditions, a thermal state time-series is constructed for each generator using transition times between the states (*HotToWarm* and *WarmToCold*) provided in Table 3. Startup fuel which may be different from the primary fuel type in some cases (e.g. for coal generators, startup fuel is a 68%-32% oil/coal mixture). Figure 3 shows an example of the emissions associated with a coal generator. Startup emissions in 2011 were 0.14MtCO_2 bringing total emissions to 11.78MtCO_2. This compares to verified emissions of 11.84MtCO_2.

[2]One peat generator ("ED1") was 15% co-fired with biomass material in 2011. This means that, under emissions rules, it's net emissions are reduced by the same factor.

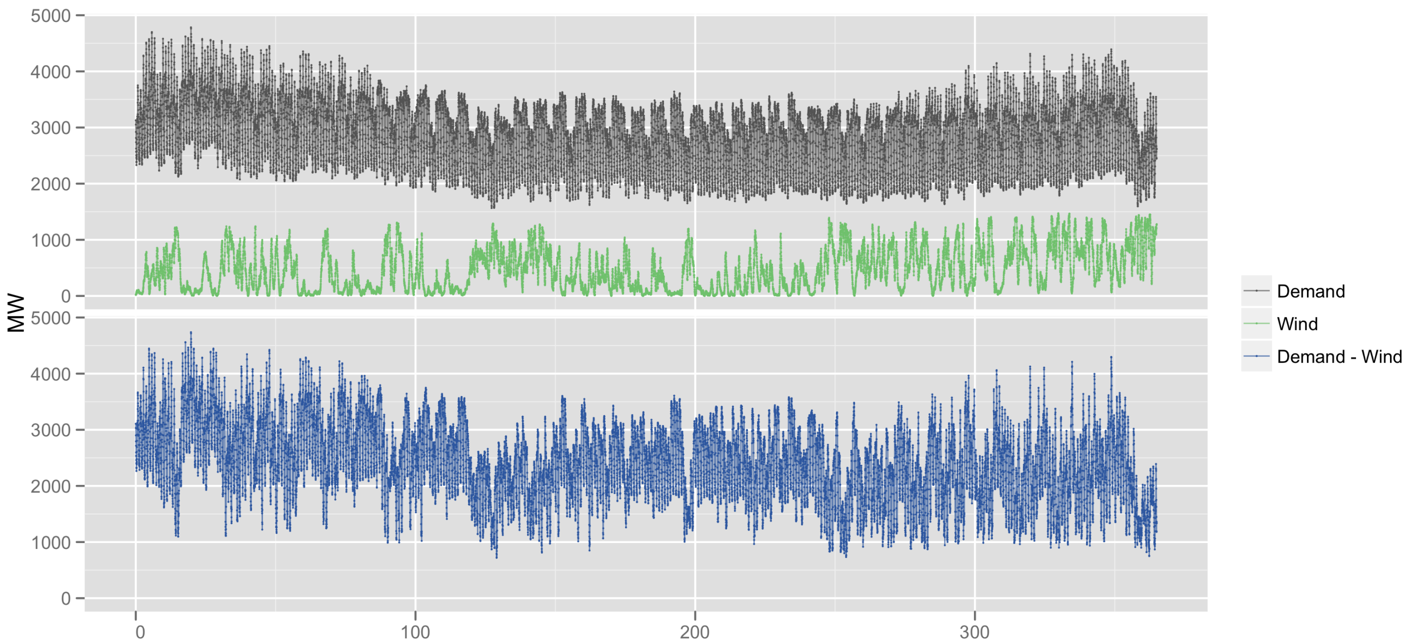

Figure 1 – Upper: Demand (MGLF, black) and estimated wind power generation (green). Mean demand is 2813MW. Mean wind was 467MW with capacity factor was 30%. The correlation between wind generation and demand is close to zero (≈ 0.05). Lower: Effective demand (= demand - wind) as seen by conventional plant. Effective demand is $\approx 38\%$ more volatile than system demand.

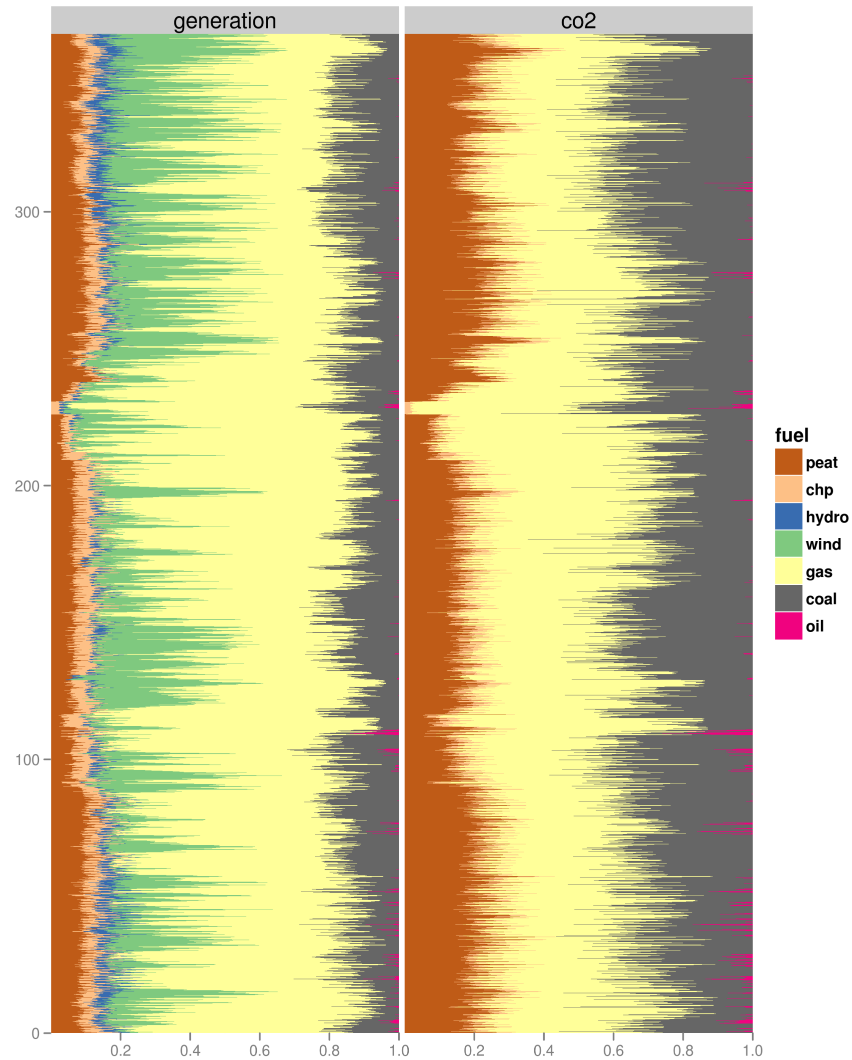

Figure 2 – Left: Half-hourly fuel mix time-series (generation fraction) for 2011 derived from SEMO data. Right: corresponding CO_2-mix time series. The vertical scale is day of year. Mean generation fractions were: (1) gas (+chp) 58% (2) wind 17% (3) coal 15% (4) peat 8%. Mean emissions fractions on the other hand were (1) gas (+chp) 49% (2) coal 31% (3) peat 19%

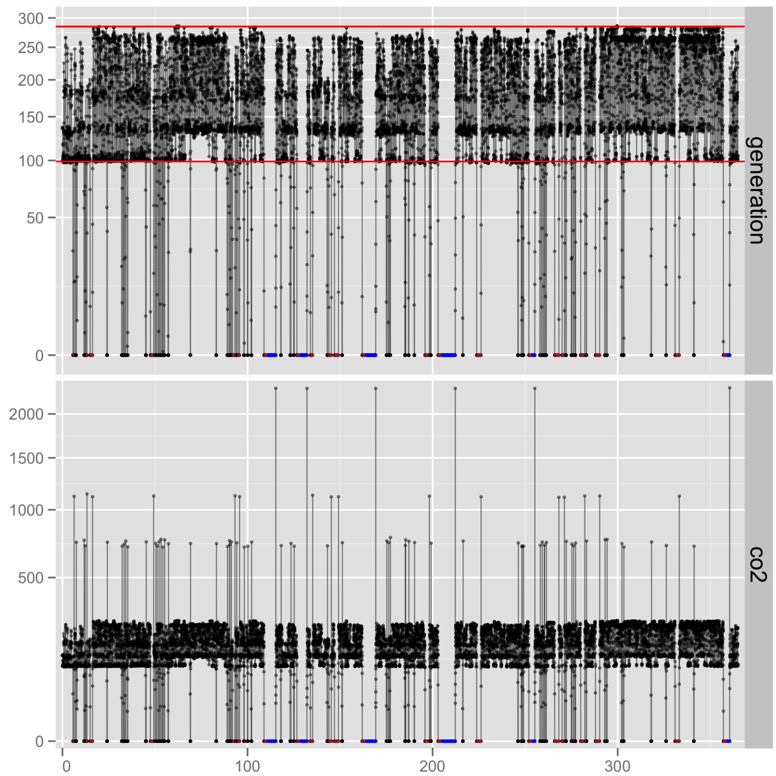

Figure 3 – Top: Metered generation(MW) from coal generator MP2 (Moneypoint power station) during 2011. The red lines correspond to maximum and minimum stable operating capacities. Thermal state (Cold, Warm Hot) are indicated by colours blue, brown, black. Bottom: corresponding CO_2 emissions rate (tCO_2/h). The spikes in emissions correspond to cycling (start up) events. For visualisation and modelling convenience, all cycling emissions are assumed to occur within a half hour interval.

As a consistency test of the emissions model, comparison can be made with annual power plant emissions reported under to the European Emissions Trading Scheme (EU-ETS) for 2011.[12] These data provide an *independent* test of the emissions model because they are based on actual fuel consumption information collected using stock accounting principles. To convert to CO_2, standard emissions factors are associated with each fuel (although in the case of coal, emissions factors can vary significantly from year to year). To make contact with these data, the emissions time-series of the 35 thermal generators are aggregated into 11 power plant and annual emissions calculated. These data provide both a consistency check and model constraint, as illustrated in 4. In all agreement is satisfactory, and is particularly good for gas base-load (Combined Cycle Gas

Turbine or CCGT) plant. It is not surprising that errors are somewhat larger for intermittently used “peaking” plant, but these form only a very small fraction of total emissions.

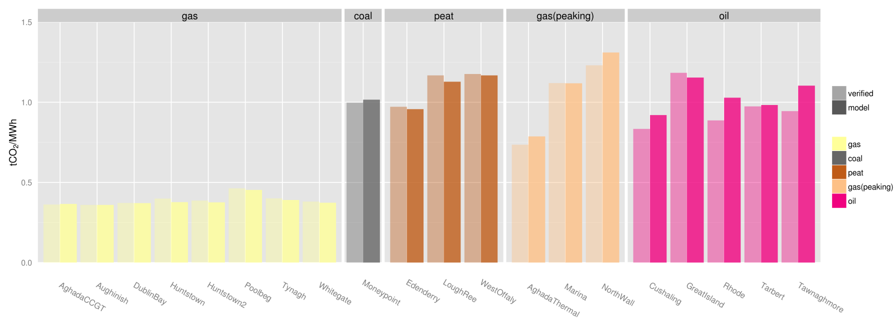

Figure 4 – Comparison of model and reported power station emissions in 2011. Carbon intensities (tCO_2/MWh) based on emissions reported under EU-ETS are shown in light colours, while modeled values are shown in heavy colors. Baseload gas (CCGT) plant have lowest emissions intensities. Emissions factors used to convert from energy units to emissions (TWh/tCO_2) were : coal = 89.9, peat = 116.7, oil = 71.4, gas= 56.9. Verified EU-ETS emissions at Aughinish include emissions unrelated to electric power generation for the grid, so these have been set to the model value.

In fact, the above emissions model is incomplete. Ramping a thermal generator burns additional fuel even when no start-ups occur. This arises when a generator is ramped between *MinCap* and *MaxCap* as in Figure 3, for example. Simply summing emissions based on the generator’s input-output curve as done above does not capture this effect. This additional source of emissions has been emphasised particularly by le Pair, Udo and de Groot[6] and is likely to be especially significant in the case of less flexible base-load plant.[18] Ramping emissions were not included in the calculation described above, primarily because no model parameterisations of this effect are available. However, in view of the good agreement between reported values and model, there is no evidence of a large missing source of emissions from ramping (order of magnitude $\sim 0.1MtCO_2$). Emissions from CCGT gas plant, in particular, seem to be accurately described. Nevertheless, on physical grounds we know such emissions do exist, and are likely to increase as wind penetration increases.

3 Results and Discussion

Fuel-mix plots[13] (Figure 2) show that wind displaces gas generation and, to a lesser extent, coal. Peat and gas CHP plant are operated on a “must run” basis. These plant respond to system demand but they are not displaced by wind. The CO_2-mix plot in Figure 2 is calculated using the emissions model described above. Coal and peat play a far larger role in the CO_2 mix. For example, peat provided only 8% of generation but produced 19% of emissions. Wind power displaces gas generation and therefore it is not surprising that periods of high wind generation are associated with lower emissions from gas plant. This can be seen clearly from Figure 5.

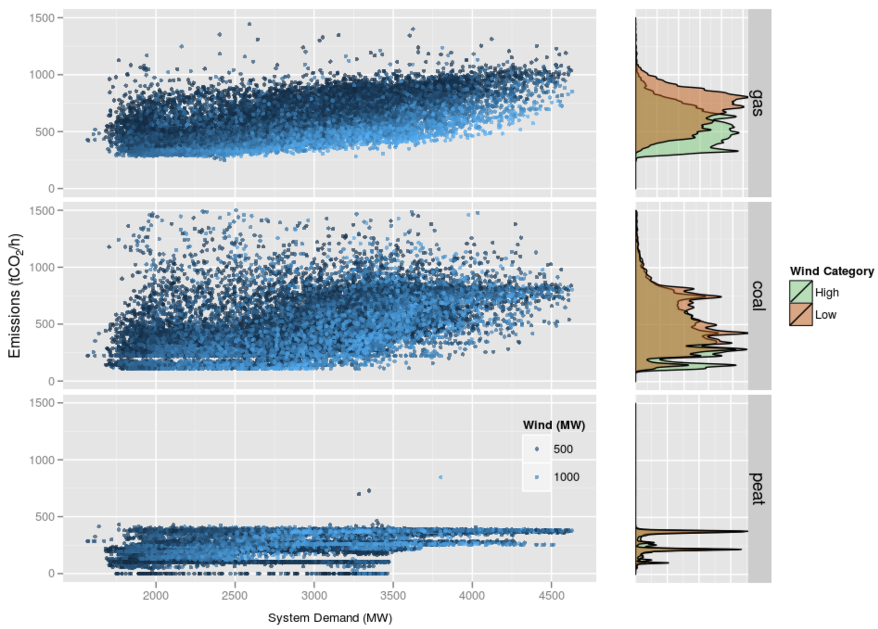

Figure 5 – Left: CO_2 emission rates for gas, coal and peat fuel generators as a function of total system demand. High wind generation is indicated in light blue, and low wind generation is shown in dark blue. Right: Empirical probability distribution for CO_2 emission rates for "high" (green) and "low" (pink wind generation i.e. lower or higher than the median wind generation. The coal and gas plant portfolio is more likely to be found in a low emission state at high wind generation. This effect is far stronger for gas than for coal.

Emissions intensity fall linearly with wind penetration. A summary of the linear regression fit is shown in Table 1. The intercept 0.53tCO_2/MWh corresponds to grid average emissions intensity in the absence of wind. The fitted slope -0.28tCO_2/MWh corresponds to emissions savings due to wind generation. The displacement effectiveness of wind power is therefore just 53%. (If start-up emissions are omitted the fit parameters become 0.52tCO2/MWh and 0.3tCO2/MWh respectively.) If there was no wind in 2011, emissions would have been 12.9MtCO_2 versus 11.8MtCO_2 observed i.e. a savings of $\approx$ 9%.

It seems surprising at first sight that emissions savings of 0.28tCO_2/MWh is less than the emissions intensity of the cleanest thermal generators on the grid, Figure 4. To understand how this arises, it is necessary to drill down and see how individual generators respond to wind generation. In general the relationship between an individual generator and total system demand (or total

	Estimate	Std. Error	t value	Pr(>|t|)
(Intercept)	0.5253	0.0008	672.53	0.0000
Wind Penetration	-0.2788	0.0035	-79.38	0.0000

Table 1 – Fit parameters and standard error for grid emissions intensity (tCO_2/MWh) vs wind penetration.

wind) is non-linear and noisy. However since linear behaviour is observed for the grid as a whole, Table 1, it can be assumed that this derives from relationships of the form $co2_g = \alpha_g D + \beta_g W$ at the individual generator level. Here $co2_g$ is emissions rate of generator g, D is system demand and W is wind power. Multiple linear regression yields the fit parameters α_g and β_g for the 35 thermal generators shown in Table **??**. Significant negative value of β_g indicates that emissions from generator g are displaced by wind. It is clear from Table **??** that most of the displacement of thermal plant emissions occurs at just four of the modern base-load gas units (CCGT).

With this information, a simple example illustrates how efficiency losses can push CO_2 savings below the average emission intensity of the CCGT generators which are displaced by wind. At full-load (1600MW, maximum efficiency) average emissions intensity of the four units is 0.35tCO_2/MWh, according to the model input-output curves. At part-load (770MW, minimum stable operating capacity) emissions intensity rise to 0.4tCO_2/MWh. Assume that initially the four CCGT plant are operating at optimal full-load1600MW and wind generation is zero. If wind generation increases to 840MW, their combined output drops to their minimum operation capacity, 770MW. The change in emissions rate per unit wind power in this scenario is (0.35 x 1600 - 0.4 x 770)/840 = 0.3tCO_2/MWh. This illustrates how efficiency losses alone can lower emissions savings below the emissions intensity of the cleanest thermal plant.

The presence of electricity imports and exports means that grid average emissions intensity can be expressed in different ways. For example, carbon intensity can be expressed with respect to total system demand (as above), system demand net of exports (i.e. "domestic demand"), or system demand net of imports (i.e. "domestic generation"). This also affects how wind power savings are expressed. In the case of Ireland in 2011, SEMO "NIJI" data show that total imports and exports were 3% and 1% of demand respectively, so that the differences between these measures of carbon intensity are relatively small. In other situations, the differences may be substantial. With respect to "domestic demand" and "domestic generation", zero-wind grid intensity were 0.53tCO_2/MWh and 0.55tCO_2/MWh respectively while wind power savings were 0.26tCO_2/MWh an 0.30tCO_2/MWh respectively. Corresponding displacement effectiveness were 50% and 56%.

generator	fuel	alpha	beta
ADC	CCGT	0.0264	-0.0502
DB1	CCGT	0.0400	0.0029
HNC	CCGT	0.0317	-0.0562
HN2	CCGT	0.0388	-0.0143
PBC	CCGT	0.0327	-0.0027
TYC	CCGT	0.0251	-0.0586
WG1	CCGT	0.0432	-0.0528
SK3	CHP	0.0076	0.0031
SK4	CHP	0.0088	0.0020
MP1	coal	0.0523	-0.0238
MP2	coal	0.0569	-0.0414
MP3	coal	0.0564	-0.0137
LR4	peat	0.0312	-0.0033
ED1	peat	0.0292	0.0042
WO4	peat	0.0260	0.0220
AD1	OGCT	0.0026	0.0126
AT1	OGCT	0.0014	0.0048
AT2	OGCT	0.0004	0.0021
AT4	OGCT	0.0001	0.0003
NW4	OGCT	0.0000	0.0000
NW5	OGCT	0.0049	0.0023
MRT	OGCT	0.0012	0.0007
GI1	OGCT	0.0002	-0.0005
GI2	OGCT	0.0001	-0.0005
GI3	OGCT	0.0007	-0.0020
RH1	oil	0.0001	-0.0001
RH2	oil	0.0000	-0.0001
TB1	oil	0.0003	-0.0008
TB2	oil	0.0002	-0.0004
TB3	oil	0.0030	-0.0084
TB4	oil	0.0017	-0.0051
ED3	oil	0.0002	-0.0005
ED5	oil	0.0002	-0.0004
TP1	oil	0.0000	-0.0001
TP3	oil	0.0000	-0.0001
All		0.5235	-0.2788

Table 2 – Displacement of generator emissions by wind power using the linear response model. The multiple regression fits assume zero intercept. Totals $\sum \alpha_g$ represents the grid average intensity, and $\sum \beta_g$ represents wind power savings (tCO_2/WMh). Most of the emissions reductions occurred at just four modern CCGT plants shown in boldface, Aghada (commissioned in 2010), Huntstown(2002), Tynagh(2006) and Whitegate (2010). The anti-correlation between wind and emissions at WO4 (West Offaly peat plant) arose because there was an outage at this plant during the summer when wind generation is lowest. The data suggest that MP2 increased to compensate.

4 Conclusion

As currently deployed, wind power is a supplementary power source whose role is to reduce fossil fuel use by displacing thermal generation. The Irish situation is typical in the sense that it has rapidly growing wind penetration embedded in a diverse portfolio of thermal plant. A detailed empirical model of operational CO_2 savings was developed for 2011. It is found that savings of 0.28tCO_2/MWh were achieved, versus a zero-wind emissions intensity of 0.53tCO_2/MWh. This estimate is at the lower end of expectations.[9] In particular, it is significantly lower than the emissions intensity of the CCGT plant which play the primary role in balancing wind generation. Effectiveness is likely to fall further as wind penetration increases.[10, 11]

Assessments of the economic or environmental benefit of wind power are not credible unless they are based on accurate emissions (and fuel) savings. This study suggests that savings may be lower than contemplated by public agencies to date. The Irish government has an ambitious target of meeting 37% of domestic electricity demand using wind power by 2020. It is a concern that at 17% wind penetration, the system is already in a regime where effectiveness is approaching $\approx 50\%$, even before significant curtailment and/or exports of wind power begin to occur.

Finally, life-cycle estimates of CO_2 emissions involved in construction and installation of wind power are sensitive to assumptions about the capacity factor, economic life of wind turbines, infrastructure requirement etc.[19] Estimates are in the range 0.002-0.08 tCO_2/MWh. At the upper end of this range, life-cycle emissions are a significant fraction of operational CO_2 savings.

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Source	ID	Name	Fuel	MinCap	MaxCap	RampUp	RampDown	ColdStart	WarmStart	HotStart	HotToWarm	WarmToCold
Aughinish	SK3	Sealrock 3 (Aughinish CHP)	Gas	40.00	83.00	6.00	6.00	1200.00	1000.00	800.00	8.00	24.00
Aughinish	SK4	Sealrock 4 (Aughinish CHP)	Gas	40.00	83.00	6.00	6.00	1200.00	1000.00	800.00	8.00	24.00
Edenderry	ED1	Edenderry	Peat/Biomass	41.00	117.60	1.76	1.76	2308.00	1084.00	436.00	4.00	48.00
ESBPG	AA1	Ardnacrusha Unit 1		12.00	21.00	6.00	6.00	0.00	0.00	0.00	12.00	48.00
ESBPG	AA2	Ardnacrusha Unit 2		12.00	22.00	6.00	6.00	0.00	0.00	0.00	12.00	48.00
ESBPG	AA3	Ardnacrusha Unit 3		12.00	19.00	6.00	6.00	0.00	0.00	0.00	12.00	48.00
ESBPG	AA4	Ardnacrusha Unit 4		12.00	24.00	6.00	6.00	0.00	0.00	0.00	12.00	48.00
ESBPG	AD1	Aghada Unit 1	Gas	36.00	258.00	5.10	5.10	4302.00	2185.00	1273.00	5.00	67.00
ESBPG	AT1	Aghada CT Unit 1	Gas	15.00	90.00	5.00	5.00	63.00	63.00	63.00	12.00	48.00
ESBPG	AT2	Aghada CT Unit 2	Gas	15.00	90.00	5.00	5.00	63.00	63.00	63.00	12.00	48.00
ESBPG	AT4	Aghada CT Unit 4	Gas	15.00	90.00	5.00	5.00	63.00	63.00	63.00	12.00	48.00
Endesa	GI1	Great Island Unit 1	Oil	25.00	54.00	0.70	1.00	562.00	449.00	218.00	12.00	48.00
Endesa	GI2	Great Island Unit 2	Oil	25.00	49.00	0.70	1.00	562.00	449.00	218.00	12.00	48.00
Endesa	GI3	Great Island Unit 3	Oil	30.00	113.00	0.70	1.50	743.00	600.00	293.00	12.00	60.00
ESBPG	MP1	Moneypoint Unit 1 FGD SCR	Coal	99.00	285.00	3.00	4.00	14620.00	6920.00	4360.00	12.00	60.00
ESBPG	MP2	Moneypoint Unit 2 FGD SCR	Coal	99.00	285.00	3.00	4.00	14620.00	6920.00	4360.00	12.00	60.00
ESBPG	MP3	Moneypoint Unit 3 FGD SCR	Coal	99.00	285.00	3.00	4.00	14620.00	6920.00	4360.00	12.00	60.00
ESBPG	MRT	Marina No ST	Gas	20.00	88.00	5.00	5.00	63.00	63.00	63.00	12.00	28.00
ESBPG	NW4	Northwall Unit 4	Gas	87.30	163.00	3.78	12.00	80.00	80.00	80.00	12.00	60.00
ESBPG	NW5	Northwall Unit 5	Gas	4.00	104.00	8.00	8.00	50.00	50.00	50.00	12.00	48.00
ESBPG	PBC	Poolbeg Combined Cycle	Gas	232.00	480.00	11.00	11.00	2800.00	1800.00	1500.00	8.00	112.00
ESBPG	WO4	West Offaly Power	Peat	45.00	137.00	0.70	0.70	750.00	600.00	450.00	12.00	60.00
Synergen	DB1	Dublin Bay Power	Gas	209.00	415.00	10.00	9.00	7700.00	2604.00	2600.00	12.00	60.00
Tynagh	TYC	Tynagh	Gas	194.00	388.50	12.50	12.50	5033.00	2944.00	2017.00	12.00	48.00
Viridian	HN2	Huntstown Phase II	Gas	194.00	404.00	20.00	20.00	644.00	531.00	318.00	12.00	60.00
Viridian	HNC	Huntstown	Gas	184.00	343.00	7.00	7.00	4772.00	2803.00	835.00	12.00	60.00
ESBPG	ADC	Aghada CCGT	Gas	213.00	435.00	12.43	12.43	2400.00	1800.00	1200.00	12.00	60.00
ESBPG	LR4	Lough Rea	Peat	68.00	91.00	1.37	1.37	500.00	400.00	300.00	12.00	48.00
Bord Gais	WG1	Whitegate	Gas	180.00	445.00	30.00	30.00	437.00	330.00	223.00	12.00	60.00
Endesa	RH1	Rhode 1	Distillate	12.00	52.00	5.00	10.00	24.00	24.00	24.00	12.00	60.00
Endesa	RH2	Rhode 2	Distillate	12.00	52.00	5.00	10.00	24.00	24.00	24.00	12.00	60.00
Endesa	TB1	Tarbert Unit 1	Oil	20.00	54.00	1.00	1.00	562.00	449.00	218.00	12.00	60.00
Endesa	TB2	Tarbert Unit 2	Oil	20.00	54.00	1.00	1.00	562.00	449.00	218.00	12.00	60.00
Endesa	TB3	Tarbert Unit 3	Oil	34.90	240.00	1.70	2.20	3180.00	1934.00	1072.00	14.00	120.00
Endesa	TB4	Tarbert Unit 4	Oil	34.90	240.00	1.70	2.20	3180.00	1934.00	1072.00	14.00	120.00
Endesa	TP1	Tawnaghmore 1	Distillate	12.00	52.00	5.00	10.00	24.00	24.00	24.00	12.00	60.00
Edenderry	ED3	Cushaling	Distillate	20.00	58.00	5.00	5.00	20.00	20.00	20.00	0.50	1.00
Edenderry	ED5	Cushaling	Distillate	20.00	58.00	5.00	5.00	20.00	20.00	20.00	0.50	1.00
Endesa	TP3	Tawnaghmore 3	Distillate	12.00	52.00	5.00	10.00	24.00	24.00	24.00	12.00	60.00
ESBPG	ER1	Erne Unit 1		4.00	10.00	5.00	10.00	0.00	0.00	0.00	12.00	48.00
ESBPG	ER2	Erne Unit 2		4.00	10.00	5.00	10.00	0.00	0.00	0.00	12.00	48.00
ESBPG	ER3	Erne Unit 3		5.00	22.50	10.00	22.50	0.00	0.00	0.00	12.00	48.00
ESBPG	ER4	Erne Unit 4		5.00	22.50	10.00	22.50	0.00	0.00	0.00	12.00	48.00
ESBPG	LE1	Lee Unit 1		3.00	15.00	2.40	15.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LE2	Lee Unit 2		1.00	4.00	0.60	4.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LE3	Lee Unit 3		3.00	8.00	1.50	8.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LI1	Liffey Unit 1		3.00	15.00	5.00	10.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LI2	Liffey Unit 2		3.00	15.00	5.00	10.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LI4	Liffey Unit 4		0.40	4.00	2.00	2.00	0.00	0.00	0.00	12.00	48.00
ESBPG	LI5	Liffey Unit 5		0.20	4.00	0.03	2.00	0.00	0.00	0.00	12.00	48.00
ESBPG	TH1	Turlough Hill Unit 1		5.00	73.00	210.00	270.00	0.00	0.00	0.00	12.00	48.00
ESBPG	TH2	Turlough Hill Unit 2		5.00	73.00	210.00	270.00	0.00	0.00	0.00	12.00	48.00
ESBPG	TH3	Turlough Hill Unit 3		5.00	73.00	210.00	270.00	0.00	0.00	0.00	12.00	48.00
ESBPG	TH4	Turlough Hill Unit 4		5.00	73.00	210.00	270.00	0.00	0.00	0.00	12.00	48.00

Table 3 – (a) The 50 grid-connected non-wind generators used in this study. MinCap and MaxCap are minimum and maxiumum stable operating capacities (MW), RampUp and RampDown are maxiumum ramp up rates (MW/min), ColdStart, WarmStart and HotStart are thermal state dependent startup energy costs (GJ). HotToWarm and WarmToCold are cooling down times (hours). Adapted from Ref. [16]

ID	Name	Fuel	NoLoad	Cap1	Cap2	Cap3	Cap4	IHRS01	IHRS12	IHRS23	IHRS34
SK3	Sealrock 3 (Aughinish CHP)	Gas	100.00	40.00	83.00			5.00	5.00		
SK4	Sealrock 4 (Aughinish CHP)	Gas	100.00	40.00	83.00			5.00	5.00		
ED1	Edenderry	Peat/Biomass	497.60	88.00	112.00	118.00		3.93	8.95	8.95	
AD1	Aghada Unit 1	Gas	182.83	120.00	190.00	258.00		7.81	8.45	8.52	
AT1	Aghada CT Unit 1	Gas	295.05	40.00	90.00			8.10	10.05		
AT2	Aghada CT Unit 2	Gas	295.05	40.00	90.00			8.10	10.05		
AT4	Aghada CT Unit 4	Gas	295.05	40.00	90.00			8.10	10.05		
GI1	Great Island Unit 1	Oil	51.07	25.00	45.00	54.00		13.59	13.59	13.67	
GI2	Great Island Unit 2	Oil	51.07	25.00	45.00	49.00		13.59	13.59	13.67	
GI3	Great Island Unit 3	Oil	102.65	30.00	98.00	113.00		10.88	10.88	10.98	
MP1	Moneypoint Unit 1 FGD SCR	Coal	173.77	195.00	280.00	285.00		9.48	9.58	14.09	
MP2	Moneypoint Unit 2 FGD SCR	Coal	173.77	195.00	280.00	285.00		9.48	9.58	14.09	
MP3	Moneypoint Unit 3 FGD SCR	Coal	173.77	195.00	280.00	285.00		9.48	9.58	14.09	
MRT	Marina No ST	Gas	258.84	47.00	81.00	88.00		8.66	9.48	11.41	
NW4	Northwall Unit 4	Gas	351.34	87.00	115.00	162.00		6.07	6.84	8.23	
NW5	Northwall Unit 5	Gas	333.61	50.00	104.00			9.03	9.70		
PBC	Poolbeg Combined Cycle	Gas	452.11	480.00	510.00			6.13	6.99		
WO4	West Offaly Power	Peat	118.67	137.00				9.00			
DB1	Dublin Bay Power	Gas	479.34	203.00	415.00			5.00	5.16		
TYC	Tynagh	Gas	604.00	194.00	250.00	404.00		4.00	5.46	5.74	
HN2	Huntstown Phase II	Gas	603.60	195.00	230.00	412.00		4.00	5.62	5.74	
HNC	Huntstown	Gas	541.20	200.00	230.00	250.00	352.00	4.00	5.19	5.99	6.01
ADC	Aghada CCGT	Gas	592.39	213.00	430.00	435.00		4.00	5.40	5.56	
LR4	Lough Rea	Peat	85.29	91.00				8.65			
WG1	Whitegate	Gas	666.68	185.00	399.00	460.00		4.00	5.26	6.11	
RH1	Rhode 1	Distillate	85.01	12.00	52.00			9.82	9.82		
RH2	Rhode 2	Distillate	85.01	12.00	52.00			9.82	9.82		
TB1	Tarbert Unit 1	Oil	44.66	20.00	46.00	54.00		11.63	11.63	11.75	
TB2	Tarbert Unit 2	Oil	44.66	20.00	46.00	54.00		11.63	11.63	11.75	
TB3	Tarbert Unit 3	Oil	247.61	35.00	100.00	180.00	240.00	8.07	8.07	9.06	9.15
TB4	Tarbert Unit 4	Oil	247.61	35.00	100.00	180.00	240.00	8.40	8.40	9.43	9.64
TP1	Tawnaghmore 1	Distillate	86.62	12.00	52.00			10.00	9.59		
ED3	Cushaling	Distillate	85.00	58.00				9.00			
ED5	Cushaling	Distillate	85.00	58.00				9.00			
TP3	Tawnaghmore 3	Distillate	86.62	12.00	52.00			10.00	9.59		

Table 4 – (b) Additional parameters for 35 grid-connected thermal generators used in this study. NoLoad is the extrapolated zero load (Cap0) energy use (in GJ/h). Capacity Points (Cap1 etc, MW) are used to specify the heat rate curve. IHRS values are Incremental Heat Rate Slopes (GJ/MWh) defined between each pair of capacity points. These data are used to create static CO_2 emissions vs generation curves (CO_2/h vs MW) or "input-output" curves for each generator. Adapted from Ref. [16]