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Working Paper No. 334

December 2009

The Likely Economic Impact of Increasing Investment in Wind on the Island of Ireland*

Conor Devitt, Seán Diffney, John Fitz Gerald, Seán Lyons and Laura Malaguzzi Valeri

Subsequently published in "Investment in Electricity Infrastructure in a Small Isolated Market: the Case of Ireland", Oxford Review of Economic Policy, Vol. 25, No 3, December 2009, pp.469–487, http://dx.doi.org/10.1093/oxrep/grp022

Abstract: Like most countries Ireland faces the double target of decreasing emissions and keeping energy costs low to maintain competitiveness of the economy. The two goals are not always compatible. This study measures the effect of increasing wind in electricity generation on the total electricity costs for the Island of Ireland for the year 2020 under a variety of scenarios on fuel and carbon costs, generating plant portfolio mixes and electricity demand growth. We find that with high levels of interconnection 6000MW of installed wind capacity are likely to reduce overall costs, especially if the price of natural gas stays high. The sensitivity of the results to the level of interconnection suggests that it is important for interconnection to be operated and governed as efficiently as possible. We also find that the deregulated all-island system will face major challenges moving into the future since returns to traditional fossil-fuelled plants might not be sufficient to create new (needed) investment when wind penetration is high.

Keywords: electricity; interconnection; Ireland; wind generation; returns to investment

Corresponding Author: Laura.Malaguzzi Valeri@esri.ie

* This work has benefited from many discussions with the Department of Energy Communications and Natural Resources, the Commission for Energy Regulation, EirGrid and various Irish industry participants. All remaining errors are our own. Funding from the ESRI Energy Policy Research Centre is gratefully acknowledged.

The Likely Economic Impact of Increasing Investment in Wind on the Island of Ireland

1. Introduction

Public policy, both domestic and EU, provides the context within which there is likely to be a major expansion in the deployment of wind generation on the island of Ireland over the coming decade. Underlying the major policy initiatives is the world-wide imperative of tackling the problem of global warming. At the level of the EU, the Emissions Trading Scheme (ETS) is now fully implemented and it is likely to be a permanent fixture, even after the current phase ends in 2012. In addition, there are a series of targets for deployment of renewable energy, also predicated on the need to take action to curb greenhouse gas emissions. In the case of Ireland government policy was changed in 2007 to set a target that 40 per cent of electricity would be generated from renewable sources by 2020.

In addition to concern about global warming, domestic and EU policy is also focused on the issue of security of energy supply. While to date very limited policy initiatives have been taken at either an EU or an Irish level to diversify the sources of energy, including electrical energy, this is a continuing issue of concern for policy makers. In the case of Ireland, these concerns were set out in the Energy White Paper published in 2007. To some extent the renewables objective can be seen as one instrument promoting reduced dependence on imported fossil fuels.

The third major issue for energy policy, both domestic and EU, is the need to ensure that energy supplies are available at minimum cost, enhancing the competitiveness of the economy. This objective is not necessarily consistent with the first two objectives of policy – tackling global warming and ensuring security of energy supply. This paper considers how the policy target of generating 40 per cent of electricity from renewable sources by 2020 is likely to impact on the welfare of consumers and producers on the island and on the competitiveness of the Irish economy. It explores how the renewables objective fits in with the overall objectives of energy policy.

This paper adds to previous results on the costs and benefits of a major increase in wind generation by examining the sensitivity of these earlier results to different assumptions on energy and carbon prices. It also explores the importance for the results of different levels of interconnection between the electricity system on the island of Ireland and that in Great Britain.

While the three major issues for energy policy have been clearly identified, the development of relevant policy instruments to target these policy objectives has been a slow process. The EU first proposed a joint energy/carbon tax in the early 1990s. However, the eventual policy instrument chosen, the Emissions Trading System (ETS), only began in 2004 on a pilot basis. The price which resulted for carbon emissions in the trial phase was generally quite low. Since 2008 the current phase of the trading regime has seen somewhat higher prices, though its impact has been blunted by the grandparenting of the emissions allowances.

In the case of renewables there have been a number of domestic schemes which have encouraged the deployment of renewable electricity generation. In the late 1990s a series of AES (Alternative Energy Schemes) were introduced providing different forms of guarantee for investors. The current REFIT (Renewables Feed-in Tariff) scheme provides a guaranteed price for electricity generated from wind. However, the market price last year was sufficiently high that wind generators obtained all their guaranteed return from the market without the need for any subsidy from consumers. Thus, to date, the deployment of renewables has been achieved at little cost to consumers.

These policy changes have been superimposed on a rapidly changing market place for electricity. The gradual removal of the obstacles to entry in the electricity market began a decade ago. Since then there has been a slow erosion of the monopoly position of the ESB. The development of a competitive market in generation was greatly facilitated by the creation of the All-Island market for electricity culminating with the launch in November 2007 of the Single Electricity Market (SEM). This market provides a transparent wholesale market for electricity where generators bid their short-run marginal cost. A capacity payments mechanism ensures that the price received by producers approximates the long-run marginal cost of generation (Lyons et al., 2007). The development of this wholesale market has proved very important in facilitating the expansion of wind generation on the system. For the future, the prospective returns from selling into this market will be a key determinant of the level of investment in wind generation.

This paper expands on the results of two earlier studies by EirGrid and the CER and it provides a lot more detail on the results presented in Diffney et al. (2009). As with the earlier two studies this paper examines the costs and benefits of increased wind generation capacity in the all-island system for the year 2020. It differs from these earlier studies in considering the effects of different levels of interconnection with GB. In addition, this study considers a range of different scenarios on the price of fuel and carbon and how changes in these prices would affect the costs and benefits of different levels of wind generation. Finally, this study assumes that the system is balanced by constraining off wind to ensure that conventional plant is not forced to cycle in an extreme way. The summary results presented in Diffney *et al.* (2009) are expanded on in this paper.

The key characteristics of the new Single Electricity Market are discussed in Section 2. The model of the electricity system used in this study is set out in Section 3. This study expands on the results of earlier work by considering a wider range of assumptions and these varying assumptions are discussed in Section 4. Section 5 discusses two previous studies of the implications for the Irish electricity system of a major expansion in electricity generated from wind. The results obtained using the electricity model are set out in detail in Section 6. Conclusions are drawn in Section 7 both in terms of the likely costs and benefits of current policy on renewable electricity and also on the necessary policy initiatives which will be needed to maximise the return for the economy from this major investment programme.

2. The Single Electricity Market

The Irish All-Island Market (AIM) started in November 2007 and includes both the Republic of Ireland and Northern Ireland. The AIM is characterized by a single pool market for wholesale electricity, where all generators submit their bids, and a system of capacity payments. Participation in the pool is mandatory for any generator with an export capacity larger than 10 megawatts (MW). Each plant that generates electricity during a given period is paid the same price, which is determined by the bid of the most expensive plant necessary to meet electricity consumption in that period.

For each trading day generators offer their bids up to a day ahead of trade. Each bid consists of a maximum of 10 price-quantity pairs that are subject to price floors and caps set by the regulator.[1] In addition generators submit the cost of no load (representing

[1] These limits are currently quite loose. The price floor is set at € -100/MWh, whereas the price cap is set at €1,000/MWh. Neither of these limits had been reached up to April 2008 (Single Electricity Market Committee, 2008).

operation costs invariant to actual generation), ramp up costs (the cost of increasing generation volumes) and start-up costs (the cost of starting the unit from cold, warm or hot states). The bid pairs, no load and ramp up costs are the same for all periods of the relevant day. Generators can also attach technical conditions to their bid, including a minimum level of generation and a minimum number of periods of generation or downtime. Bidding principles require that generators bid their short run marginal cost (mainly fuel and carbon dioxide permit costs). If these principles are disregarded regulators reserve the right to move to enforceable bidding rules. It is relatively easy for regulators to verify that the prices quoted are in line with the fuel price actually paid by generators, which makes for a fairly transparent market.

Every year the Commission for Energy Regulation (CER) determines the size of the pot for capacity payments. It is calculated as the price needed to cover fixed costs of a 'best new entrant' peaking plant multiplied by the volume needed to maintain a predetermined reliability standard (defined as a maximum amount of hours of lost load during the year). The pot is then distributed among generators depending on their availability. Plants that are available at times when the margin between electricity demanded and electricity supplied is tight will be allocated a relatively larger share of the pot.

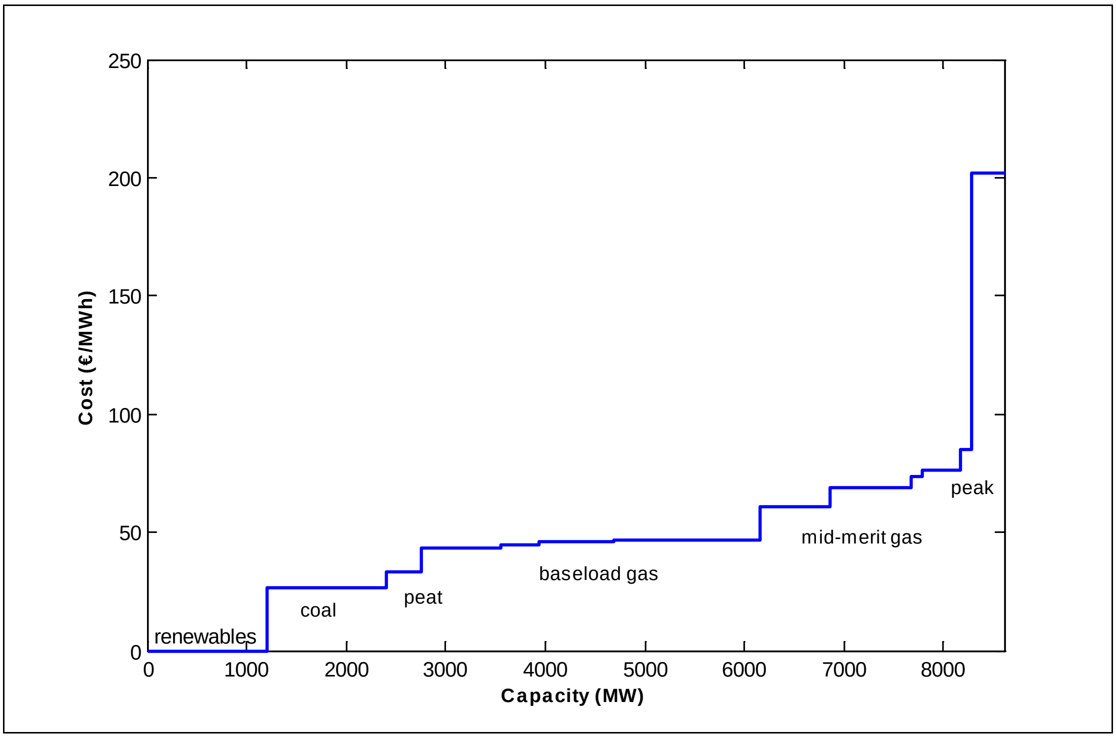
Currently there is one electricity interconnector between Ireland and Great Britain with a limited capacity of 400MW for import purposes. A further 500MW of interconnection is planned to be completed by 2012. Registered users can bid up to 10 price-quantity pairs for the interconnector between Ireland and Great Britain for every time period during the day, up to a day ahead of trade. The sum of all these bids (up to the capacity of the interconnector) is bid by the interconnector owner in the pool. The interconnector is paid capacity payments based on the actual flow along the interconnector at every period.

3. Model

The model used in this analysis is IDEM, the ESRI's model of electricity dispatch for the British Isles. This model has the benefit of being quick to run allowing investigation of a large number of different scenarios. The core of IDEM is an optimal dispatch model of the AI market. Each generating station is ranked in the merit order according to its bid price (which is assumed to be its short run marginal cost). Then electricity demand is compared to the merit order and starting from the lowest cost, plants are switched on until the demand in a period is met. For example Figure 1 shows the merit order at 2007 fuel prices. Carbon dioxide permit prices at the end of 2007 where essentially equal to 0, so they are not included in the short run marginal cost for the plants in Figure 1. If the costs were as pictured and demand were equal to 5000 MW, renewables, coal, peat and natural gas would be dispatched (subject to plant availability). If the cost of carbon dioxide permits increased significantly coal generation would become more expensive than baseload gas generation, which would be reflected by coal being pictured to the right of natural gas in Figure 1.

Once the merit order is defined and it is compared to demand the system marginal price (SMP) is set to the bid price of the most expensive plant required to meet demand in every given period. This allows estimation of the costs and revenues for each plant over the year.

Figure 1. Merit order dispatch curve for Ireland, end of 2007



The optimal dispatch model for the all-island wholesale electricity market treats the market as a mandatory pool with capacity payments. In every half hour generation has to match demand, determined by an exogenous demand curve that is assumed to be price-inelastic. The model assumes that there are no transmission constraints, no costs to increasing and decreasing the level of production and no minimum down times. Wind is constrained off the system where necessary to ensure that base-load generating capacity is not forced to cycle on and off too frequently.

While the bulk of a generator's revenue comes from the system marginal price there is also the capacity payments mechanism that is designed to cover a plant's capital costs. A total capacity pot is calculated as the product of the cost of capacity and the capacity requirement. The cost of capacity in € per kilowatt (kW) for a hypothetical Best New Entrant (BNE) is determined annually by the Regulatory Authorities. The value used in this study is the 2008 value of €79.77/kW.[2]

The required capacity is calculated by assessing the loss of load expectation (LOLE)[3] for a year and comparing this to the target loss of load, which is currently 8 hrs per year. If the LOLE is above the target then the amount of extra capacity required can be calculated and added on to total capacity to find the capacity requirement. A similar calculation can be done if the LOLE is below the target amount. The total pot based on the required capacity is then distributed between generators on the basis of their capacity and the loss of load probability in each period they are available. When the loss of load probability is high generators receive higher payments. The effect of this calculation is that when there is more capacity than the system needs the capacity payments will be less than would be needed to pay the capital costs on a new plant. When capacity is below target the capacity payment will be greater than what would be needed to remunerate a new plant – incentivising new investment.

To analyse the effects of interconnection a similar model of electricity dispatch is set up for Great Britain. We assume that the wholesale market in Great Britain is governed by the same regulations as Ireland, i.e. that it is a mandatory wholesale market where generators bid their short run marginal cost of production. Great Britain faces its own (separate) demand curve, which is also assumed to be inelastic to price changes. Fuel prices are assumed to be the same in Ireland as in Great Britain. Whereas each plant on the Irish system is modelled separately, for the British system plants of the same type and similar efficiency are aggregated. We abstract from the actual arrangements on the British market,

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[2] While all the other values in this study are provided in 2007 prices for the BNE cost we chose the value reported in SEM (2007) given that in 2008 the cost of steel was at historically high levels. For reference the BNE cost was €64.73/kW/yr in CER (2006), €79.77/kW/yr in SEM (2007) and 87.12/kW/yr in SEM (2008).

[3] The loss of load expectation is the expected number of hours in a year when some consumers will experience power shortages due to the (generally) unexpected breakdown of generating plant. Depending on the reliability of the stock of plants this determines the required spare capacity that the system needs over and above peak electricity demand.

which is governed by BETTA (British Electricity Trading and Transmission Arrangements) and is based on voluntary bilateral arrangements between generators, suppliers, traders and customers.[4]

The results allow us to compare the total cost of the electricity system under a variety of scenarios and, in addition, to analyse how the costs and benefits are spread between consumers, producers and interconnector owners.

For each scenario we measure the short run and the capital costs to generators, the costs of reinforcing or building transmission needed for the new generating plant (and also for new consumers) and the costs to consumers (based on the wholesale costs of electricity) including the costs of necessary transmission investment. We abstract from the cost of distribution and retailing of electricity to final consumers and the cost of excise and value added taxes. Wholesale costs are a significant proportion of end-user prices. In Ireland in 2008 wholesale costs (including capacity payments and dispatch balancing costs) accounted for slightly less than 60 percent of the final residential cost of electricity and about 80 percent of the final industrial cost in the Republic of Ireland.[5]

The yearly net benefit of the electricity system is defined as the sum of producer profits and interconnector profits net of the costs incurred by consumers:

$$NB = PP + IP - CC \qquad (1)$$

Total yearly producer profits are calculated as follows:

$$PP = \sum_i \left[\sum_h (P_h \cdot Q_h^i + CAP_h^i - FC_h^i) \right] - \sum_i (OC^i + K^i) \qquad (2)$$

where h indexes each half hour, P_h is the system marginal price, Q_h^i is the quantity of electricity produced by generator i, CAP_h^i is the capacity payment paid to generator i in each half hour h, FC_h^i is the cost of fuel used, OC^i is the annual operating and maintenance costs for generator i and K^i is the annualised capital cost paid by generator i.

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[4] For more on BETTA and its performance, see Newbery (2006).

[5] Final industrial and residential costs for the Republic of Ireland come from IEA (2009). The estimate of the cost of electricity in the SEM is reported in MMU (2009).

The interconnector owner is remunerated by the price difference between the two nodes in each half hour times the amount of flow in that half hour, by capacity payments, and it pays annualised capital costs:

$$IP = \sum_h (|P_h^{AI} - P_h^{GB}| \cdot fl_h) + CAP_{IC} - K_{IC} \quad (3)$$

where P_h^{AI} is the Irish system marginal price, P_h^{GB} is the system marginal price in Great Britain, fl_h is the interconnector flow, CAP_{IC} is the annual capacity payments paid to the interconnector, K_{IC} is the annual capital cost paid by the interconnector and *h* again indexes each half-hourly period.

Consumer costs are measured under the assumption that demand is inelastic and that consumers pay the wholesale price of electricity:

$$CC = \sum_h d_h P_h + CAP + T \quad (4)$$

Yearly consumer costs include the system marginal price of electricity *P* in each half hour *h* weighted by the electricity demand in that half hour d_h, yearly capacity payments *CAP*, which are a transfer from consumers to producers, and the yearly cost of transmission *T*. They do not include retail costs of electricity, distribution costs or taxes.

4. Assumptions

This study looks at the impact of increasing wind capacity on the cost of the electricity system in 2020 for a range of assumptions on fuel and carbon prices, portfolio mixes and electricity demand growth. The results of the simulations allow us to determine how the cost of the system will vary across the different dimensions.

Portfolios

This paper differs from earlier studies by considering a wider range of different scenarios. The primary focus is on the effects of different levels of wind generation on the Irish electricity system in 2020. In this paper we consider three different options – an installed capacity of 2000 MW, 4000 MW and 6000 MW in 2020. According to EirGrid (2008) 5,405 MW of Wind will have to be installed by 2020 in order to meet the target of 40% of electricity coming from renewables, while 4,371 MW will be required if 33% is to be reached. EirGrid records historic wind availability profiles[6] for each year. In this study we average results after using the wind profiles for the four years between 2005 and 2008. All wind profiles have been normalised to an average availability of 31%.

The paper also considers four different portfolios of conventional (fossil fuel) generators for Ireland and two different portfolios for Great Britain. Because of the inevitable uncertainty about the likely rate of economic growth for the period to 2020 this study examines two different scenarios on electricity demand growth.

Two portfolios are used in conjunction with high electricity demand. In the first portfolio Combined Cycle Gas Turbines (CCGTs) are assumed to be the dominant source of new capacity, while the second portfolio assumes that more Open Cycle Gas Turbines (OCGTs) are commissioned. Combined Cycle Gas Turbines are much more expensive than comparable sized OCGTs. They are more efficient in producing electricity from gas, but less flexible, in the sense that it costs more for CCGT plants to increase or decrease production than for OCGT plants. Generally CCGTs only operate efficiently when producing continuously at a high output level whereas OCGTs can operate reasonably efficiently over a much greater range of outputs.

In the low demand scenario we also use two portfolios. One portfolio uses more CCGTs and the other uses more OCGTs. However in the low demand scenario the two options are relatively similar, since there is little requirement for additional capacity above the new stations that are already planned. The low demand scenario for Ireland is generated by the ESRI's macroeconomic model HERMES and is based on the Fitz Gerald *et al.* (2008). Electricity demand in Northern Ireland is taken from SONI (2006) as far as 2013. After 2013 it is assumed to maintain the same growth rate as forecast for 2013. These assumptions imply that the island's electricity demand would be 20% above the 2007 levels by 2020. In the high growth case we assume annual increases of 2.7%[7] in Ireland out to 2020, while for Northern Ireland we use the SONI demand forecasts out to 2013 and an

[6] That is the amount of electricity generated per megawatt of installed wind generation capacity in each half hour of the relevant years.

[7] The Regulatory Authorities use a load growth scenario of 2.7% as their low growth scenario in "Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market (SEM), 2009"

annual increase of 2.7% after that. The result is an All Island demand increase of over 39% between 2007 and 2020.

Table 1 reports the assumptions on commissioning and decommissioning of fossil fuel plants up to 2020. These are common to both the low and the high demand growth scenarios.

Table 1. Additional Capacity Common to All Portfolios and Planned closures

New Capacity		Closures	
Station Name	**Capacity MW**	**Station Name**	**Capacity MW**
Kilroot OCGT 3&4	80	Great Island	216
Hydro	1	Tarbert	590
Aghada CCGT	420	Poolbeg units 1,2 and 3	461
Whitegate CCGT	445	Ballylumford units 4 and 6	340
Endesa CCGT	420	Aghada peaking unit	52
Endesa OCGT	300	Northwall units 4 and 5	267
Kilroot CCGT	440	Aghada CT units 1, 2 and 4	268
		Kilroot ST 1, 2 and GT 1, 2	534
Total	2106	Total	2728

Table 2 shows the assumptions on the commissioning of new plants when they vary across the low and high demand and the CCGT and OCGT scenarios. As mentioned previously, there if very little additional plant needed in the low demand growth scenario to meet the target LOLE.

Table 2. Assumptions on additional New Plant that are Scenario Specific

	Low Demand Scenarios				High Demand Scenarios			
YEAR	**CCGT Scenario**	**Capacity (MW)**	**OCGT Scenario**	**Capacity (MW)**	**CCGT Scenario**	**Capacity (MW)**	**OCGT Scenario**	**Capacity (MW)**
2014					OCGT 1	200	OCGT 1	200
					OCGT 2	200	OCGT 2	200
2016					CCGT 1	400	OCGT 3	200
							OCGT 4	200
2018	CCGT 1	400	OCGT 1	200	CCGT 2	400	OCGT 5	200
			OCGT 2	200			OCGT 6	200
2020					CCGT 3	400	OCGT 7	200
					OCGT 3	200	OCGT 8	200
							OCGT 9	200

We also consider two different portfolios for the British electricity system. In both cases up to 2013 the starting point is the Seven Year Statement from National Grid (2008). After that date we assume no further increase in generating capacity and no increases in electricity demand. The first of the two portfolios we refer to as “Business as usual” (BAU) and it assumes that coal plants slated to close in compliance with the Large Combustion Plant Directive are either allowed to continue running or are replaced with similar plants. We assume that nuclear plants that are slated for closure will also continue running. In the second portfolio the assumption is made that new coal and nuclear plants will not be ready to replace the retiring plants and instead new CCGTs will be built. CCGTs are faster to build than coal or nuclear plants and they are used here on the assumption that the planning process in GB will not allow the construction of new coal and nuclear plants in time. This second (gas) portfolio reflects the possibility that a failure in energy policy in Great Britain could result in low investment (see Economist, 8th August 2009, pp.27-28).

For Great Britain we assume that the government does not succeed in achieving a major deployment of offshore wind by 2020. They have ruled out major onshore wind because of its low level of acceptability. However, offshore wind is much more expensive than onshore wind.

An important conclusion of this study is that the net benefit of increasing wind generation is crucially affected by the level of interconnection between the Irish and the British electricity systems. This issue is examined by considering three different interconnection levels. The Irish electricity market is currently connected to the to the GB market through the 400MW Moyle interconnector that runs between Scotland and Northern Ireland. A second 500MW interconnector running from Woodland Co. Meath to Deeside in North Wales is to be built. This is expected to be complete by 2012 and will bring total interconnection capacity to 900MW. This is the base case for 2020. The second scenario assumes an additional 500MW interconnector bringing the total interconnection capacity to 1400MW and the third assumes that total interconnection capacity reaches 1900MW by 2020.

Table 3. Fuel Price assumptions, €/MW

Fuel Price Scenarios	Coal	Oil	Diesel Oil	Gas	Peat
1	11.2	25.1	46.0	19.4	12.0
2	11.2	46.1	84.7	35.6	12.0

3	11.2	67.2	123.3	51.9	12.0

The final important factor considered in this paper is the likely outturn for fuel and carbon prices in 2020. Given the level of volatility seen recently in energy prices we analyse the results under three fuel price scenarios. In the low fuel price scenario oil is at $60 per barrel, rising to $110 per barrel in the medium price scenario and $160 per barrel in the high price scenario (all in 2008 prices). The prices of natural gas and diesel oil are assumed to track oil prices. Both coal and peat prices are assumed constant in real terms in all three scenarios. Coal prices are fixed to enable us to examine the impact of changes in the relative prices of gas and coal. The cost of biomass is assumed to be zero (so that it does not affect the system marginal price). In each case Irish prices are the same as in Great Britain. The implications of these assumptions for the unit price of electricity generated using the different fuels are set out in Table 3.

We also consider variation in carbon dioxide permit prices. In the following results they vary from a low price of €20/tonne CO_2 (2008 prices), to a medium price of €38.2/tonne CO_2 and a high price of €60/tonne.

The peat plants in Edenderry, Lough Ree and West Offaly cofire with biomass from 2012 onwards. Cofiring increases progressively until it reaches 30% of the fuel used in these plants in 2020. The peat plants are assumed to maintain their must run status. Despite cofiring with biomass, a carbon neutral fuel, peat plants may not be profitable. Peat plants make losses when fuel prices are low under all carbon permit price scenarios and also with medium fuel price and high carbon permit prices.[8] If the peat plants are not being fully remunerated by the SEM it will be necessary to maintain a Public Service Obligation (PSO) in order to keep them running.

Table 4. Capital Cost of new plant, € million per MW of installed capacity

Type	Overnight Capital	Asset's Expected Lifetime
Wind	1.1 to 1.4	20
CCGT	0.67	25

[8] This does not take into account capital repayments. If capital repayments were included peat plants would make losses for an even larger range of scenarios.

OCGT	0.737	20
Interconnector	1.0	40

Table 4 shows the capital costs assumed for this study. The assumptions are similar to those used by the CER (2006). The nominal interest rate has been set at 8% and the inflation rate is assumed to be 2% each year out to 2020. There is a step reduction in the cost of wind capacity, declining from €1.4M at present to €1.3M in 2012, €1.2M in 2016 and reaching €1.1M by 2020. Loans are assumed to be fully repaid after 15 years, but the annual cost is spread over the whole life of the asset.

Table 5. Loss of Load Expectation (LOLE) for Different Levels of Wind

Wind \ Interconnection	900 MW	1400 MW	1900 MW
2000MW	6.30	0.78	0.08
4000MW	3.71	0.45	0.05
6000MW	2.62	0.32	0.03

The different generating portfolios do not have an identical likelihood of meeting consumer's demand over every time period. Table 5 displays the expected number of hours per year in which supply would be unable to meet demand. Each of the options is well below this 8hr / year target, meaning that there is an excess of generation capacity. As we increase the amount of wind on the system we do not remove a similar amount of existing generation capacity. Thus in the case of 6000MW wind and 1900MW Interconnection the LOLE is at its lowest at just 0.03 hours per year. The difference between the effect of interconnector capacity and wind capacity on LOLE is striking. Despite increasing in jumps of 2000MW additional wind capacity reduces LOLE by much less than the addition of just 500MW of interconnection.

The model does not deal with some potentially important aspects of the All-Island electricity market. Costs associated with damage done to plants due to repeated turning on and off of stations, known as cycling costs, have been ignored. These costs are hard to quantify and estimates cover a wide range. Instead the problem has been simplified by "constraining on" a number of base-load stations to avoid them cycling too often. Start-up costs have also been excluded, as these are highly related to the rule used to constrain on plants. In addition the cost of maintaining reserve generation in case of forced outage has not been included. Uplift payments to producers are used to cover any start-up costs that are not met by the system marginal price and these payments have not been modelled as a part of this analysis. We have not made any estimate of the cost of ongoing capital payments for plants that were already commissioned in 2005. These payments will be the same in each scenario and so will not impact on the ranking of different capacity choices.

The interaction between the Irish and GB markets has been simplified: rather than model the contract based GB market we have instead modelled the GB market in the same way as the All-Island market. The GB market produces a system marginal price in parallel to the Irish market and then electricity is assumed to be exported from the lower price market to the higher price market through the interconnector. This assumption is likely to cause some overestimation of interconnector flows.

To decide which baseload plants will be constrained on the model is run in three stages. First the model is run with a relatively low level of wind (2000 MW). A plant is assigned baseload status for one month if on average it is running at above its minimum stable capacity during that month. In the second stage only these plants are available at their minimum stable capacity and the demand for each month is set at the minimum demand in that period. The third stage uses the demand that has not been met by the base-load plants, and the capacity used is the residual base-load capacity, along with mid-merit, peaker and wind generators. This procedure is carried out to ensure a degree of stability in the system by maintaining continuity of generation. It also reduces the cycling requirement; however it will inevitably lead to higher system marginal prices than would otherwise be the case as cheap wind electricity is curtailed in favour of higher price base-load electricity.

Last but not least, we do not take into account potential environmental externalities of wind generation. These include disamenity effects caused by their location in otherwise non-industrial areas and possible land use effects that mostly arise if wind farms are located on intact peat land.

5. Earlier Studies

This paper follows two earlier significant studies of the effects of increased renewable generation on the Irish electricity market. The report "Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market" (CER, 2009), published by the CER and NIAUR (together the Regulatory Authorities or RAs), aimed to "assess the effect of increasing wind penetration on …the ability of the Single Electricity Market (SEM) to operate efficiently and effectively". It built on the All Island Grid Study (AIGS) (DCENR and DETINI, 2008), which assessed the ability of the power system and the transmission network to absorb large amounts of electricity from renewable sources. These studies examined the impact of increased wind generation in the Irish electricity system on the total cost of generation. They examined how the cost of increased wind penetration is affected by varying a number of key assumptions.[9]

Table 6. Generating Portfolios Used in Studies

	Wind Capacity	Base Renewables	Other Renewables	Conventional Capacity
Portfolio 1	2000 MW	180 MW	70 MW	CCGT & OCGT
Portfolio 2	4000 MW	180 MW	70 MW	CCGT
Portfolio 3	4000 MW	180 MW	70 MW	OCGT & ADGT
Portfolio 4	4000 MW	180 MW	70 MW	CCGT & Coal
Portfolio 5	6000 MW	360 MW	285 MW	CCGT

The All-Island Grid Study examined five generation portfolios with different compositions of conventional and renewable plants. CER (2009) uses the same five portfolios, reported in Table 6. All portfolios assume the retirement of 1800 MW of generating capacity by 2020 and include various combinations of wind capacity, base renewables (renewables which can contribute to base-load, such as biomass) and ‘other’ renewables (wave and tidal energy). The conventional generating capacity varies across portfolios, combining different amounts of base-load natural-gas fuelled plants (CCGTs) with mid-merit open cycle gas turbines (OCGTs) and aero-derivative gas turbines (ADGTs). In portfolio 4 there is also a large new coal-fired station. The research outlined in this paper includes similar portfolios with the exception of scenario which included an additional coal plant.

In both previous studies increased wind generally leads to lower system marginal prices (SMPs). However, the composition of conventional generation is also important for SMPs. More wind might impose additional costs on conventional plants by forcing them to increase and decrease their generation frequently to complement wind patterns. The net effect of more wind might therefore be a higher SMP, even though the marginal cost of wind-generated electricity is close to zero.

[9] Throughout this paper these studies are referred to as DCENR (2008) and CER (2009).

These studies suggest that the intermittent nature of wind may also increase price volatility since at times of high wind generation the SMP can significantly fall. On the other hand, increased wind generation can limit exposure of the system to the volatility of conventional fuel prices. The net effect is uncertain.

Carbon emissions decrease with increased wind capacity on the system, as long as conventional plants are mostly gas-fuelled CCGTs and there is sufficient interconnection to Great Britain. The two studies report that between 41 per cent and 42 per cent of electricity demand can be met by wind generation, while still maintaining a reliable electricity system. Incentives for investment in new wind generators and new interconnectors are judged to be strong, though financial support could be required when fuel prices are low, implying a lower system marginal price. It is unclear whether incentives for new conventional thermal generation are sufficient.

CER (2009) treats the two interconnectors with Great Britain separately: the Moyle interconnector has an import capacity of 400 MW and an export capacity of 500 MW, while the East-West interconnector has a capacity of 500 MW in both directions. DCENR (2008) treats interconnection in aggregate: the interconnectors have a total capacity of 1000 MW, with 100 MW of this available as spinning reserve. The research described in this paper combines the 400 MW Moyle capacity and 500 MW East-West capacity for a total of 900 MW of interconnection for the base case for 2020. Two further scenarios assuming additional interconnection are considered in this paper, with total capacity reaching 1400 MW and 1900 MW respectively. No allowance for spinning reserve is made in the analysis in this paper.

New generators in DCENR (2008) are assumed to maintain the same availability rates as those of similar or equivalent existing plant; the CER (2009) study and the research described in this paper assume higher availability rates for new plants.

All of the studies assume that the wholesale trading arrangements in Great Britain match the ones in Ireland. The DCENR (2008) study takes the British generation portfolio shown in SONI (2006) as a basis. This report forecasts the British portfolio out to 2012/2013, and thereafter there are minor modifications to increase wind capacity. The CER (2009) study uses a stylised model of the British market, modelled by consultancy KEMA using the modelling tool PLEXOS. Great Britain is composed of a single node with ten generating units, representing the total generation capacity of the British market divided by fuel type.

Table 7. Assumptions on Fuel price assumptions (2007 € per MWh)

Fuel	EirGrid	CER ROI		This Paper		
	central	central	low	low	medium	high
Coal	7.24	18.05	9.09	11.2	11.2	11.2
Gas (baseload)	22.34	45.81	23.27	19.4	35.6	51.9
Gas (midmerit)	23.08	45.81	23.27	19.4	35.6	51.9
Gasoil	33.88	73.38	39.87	46.0	84.7	123.3
Fuel Oil	37.97	43.84	22.96	25.1	46.1	67.2
Peat	14.06	12.82	6.44	12.0	12.0	12.0

Table 7 compares the assumptions on 2020 fuel prices made in the three studies. Table 8 shows the assumed carbon permit prices. In the CER (2009) study prices for the central scenario were based on a snapshot of market prices in July 2008. This captured a short-lived peak in prices and prices fell considerably soon after, so the prices used in their low price scenario are more in line with those used in the other two studies.

DCENR (2008) uses 2006 prices with GB fuel prices assumed the same as in Ireland. The exception is the price of gas which is assumed to be 5 per cent lower in GB. CER (2009) measures investments and fixed operation and maintenance costs in 2009 prices.

Table 8. Carbon Price Assumptions (2007 € per tonne)

	Eirgrid	CER	This paper
Central	31.47	28.82	38.2
High	62.94	43.23	60
Low	n.a.	14.41	20

DCENR (2008) assumed that electricity demand would grow by 3% per year from 2003, reaching a total energy demand of 54 terawatthours (TWh) in 2020, with a maximum load of 9600 MW. The CER (2009) central scenario also assumes total electricity consumption in 2020 to be 54 TWh, but with peak load 10407 MW. It also presents results for a lower demand growth of 2.7% per annum. The research described in this paper uses 2.7% as its high growth case, resulting in electricity demand in 2020 39% higher than in 2007, while a low growth case results in a 20% increase in demand from 2007 to 2020.

DCENR (2008) explicitly accounts for the time and fuel costs associated with thermal plant increasing or decreasing generation (ramping), whereas the CER (2009) study and the results shown in the current paper do not. This could lead the latter two to underestimate the SMP level and its volatility in the presence of intermittent generation. The ESRI model assumes zero ramping costs and times, effectively making generation completely flexible and allowing optimal response to wind conditions, as in the RA model.

The AIGS model, using 2006 wind data, assumes a wind capacity factor of approximately 35%; the RA model divides the island into 3 regions, with wind capacity factors of 32.0%, 32.3% and 31.4% respectively; the ESRI averages results across four different load curves derived from 2005-2008 historic wind. The ESRI model assumes a wind load factor of about 31% for the island.

The RAs treat the investment and capital costs for existing plants as sunk costs. This is largely in common with the AIGS, which states that "to examine the cost recovery for existing, conventional generators an assessment of the status of depreciation of the assets would be necessary". The AIGS includes the annualised cost of investment in all renewable generation, both existing and new; the RAs treat capital costs of existing renewable generation as sunk costs. This study uses similar capital costs to the RA study. All three studies assume a Weighted Average Cost of Capital (WACC) of 8%.

The RA study assumes that the operating and maintenance (O&M) costs increase as plants get older. It assumes that existing thermal plant have 50% higher O&M costs than equivalent new plants. The RAs perform a sensitivity analysis of the units that are most likely to see increased costs following more frequent increases and decreases in generation by increasing their variable operating and maintenance costs by an arbitrary amount of 50%.

The research described in this paper ignores startup costs, cycling costs and startup times, and assumes plants to be perfectly flexible.

Finally, capacity payments in the CER (2009) study are calculated using the 2009 draft Best New Entrant peaker price of €81.24 / kW / year. The research described in this paper uses the 2008 value of €79.77 / kW / year, while capacity payments are omitted from the DCENR (2008) analysis. None of the studies, including this one, take account of the government's REFIT (renewable energy feed-in tariff) scheme for renewable generators in calculating generator revenues.

Results of Earlier Studies

All three studies show that the costs and benefits of wind generation are greatly affected by fuel and carbon prices. The results of the three studies are therefore comparable only when assumed fuel prices are similar, so in this section we present the low price scenario results for the CER (2009) study.

The CER (2009) study concludes that increased wind generation capacity will significantly decrease the system marginal price unless it is “accompanied by an increase in the overall penetration of Open Cycle Gas Turbines (OCGTs)”. The conclusion that a portfolio with a large number of OCGTs increases costs is supported by the results of the current study.

The CER (2009) study finds that increased wind penetration results in a “transfer of income from generators to consumers … irrespective of the level of fuel and carbon prices”. Increased wind generation has a beneficial economic effect under their central fuel price scenario. When fuel prices are low, however, higher levels of wind capacity are associated with higher overall costs to the system as a whole. Compared to Portfolio 1, with its 2000MW of wind capacity, the portfolios with higher wind penetration have costs that are between 3% and 8% higher.

When fuel and carbon prices are low the average SMP and the annual total pool revenue are between 36% and 43% lower than in the central scenario. Variable costs are also reduced, by between 43% and 45%. When demand growth is low, at 2.7% per annum, the reserve margin is, not surprisingly, higher given that the level of installed capacity is the same in both cases. Additionally, the SMP is 6% to14% lower than in the higher demand growth scenario.

As mentioned earlier, increased wind penetration might increase price volatility since it drastically decreases the SMP at times of high wind. On the other hand it might decrease volatility by limiting the effect of the volatility of fuel prices. The DCENR (2008) paper finds that higher wind generation capacity increased price. The CER (2009) study reported that additional coal capacity reduced this volatility, and the DCENR (2008) study suggests this increased wind capacity can also serve to reduce the volatility of electricity prices arising from fluctuations in the price of conventional fuels.

In the CER (2009) study increased wind capacity was found to lower carbon emissions, except in the portfolio with additional coal capacity. The DCENR (2008) study supports this finding, on the assumption that a second interconnector to Great Britain is built. Emissions are lower when the thermal plants are mostly base-load CCGTs rather than when there are more mid-merit gas-fuelled plants such as OCGTs. Despite the reduction, it is not sufficient to meet the target of a 21% decrease of emissions with respect to 2005. When fuel prices are low, coal generation is displaced by natural gas fuelled generation and carbon emissions are reduced by between 5% and 16% compared with the central case. When demand grows more slowly, emissions fall by between 10% and 13% across portfolios. However, analysis is not performed on these two conditions combined.

The CER (2009) study finds that the flow across the interconnector is predominantly from Great Britain, where the system price is on average lower, to Ireland. Volumes imported generally fall as installed wind capacity increases

In the CER (2009) study increased wind capacity reduces the SMP and has the knock-on effect of lowering the energy market revenue significantly. New and existing wind generators make "substantial economic rents" under the CER (2009) central fuel price scenario, although new wind generation would "need financial support" under the lower fuel price assumption. There is little incentive for existing generators to exit the market regardless of the amount of wind on the system, but it is not clear that there are sufficient incentives to invest in new thermal plant. Low fuel prices, or required returns on capital greater than 8%, could cause particular difficulties in this area.

When electricity demand grows slowly, the energy market revenues fall by between 16% and 24% and, although variable fuel costs decrease as well, generators' profits are reduced by between 34% and 50% across portfolios.

The CER (2009) study concluded that "across all scenarios in 2020 … on the whole the market is viable for new and existing generation, both thermal and renewable"

The CER (2009) study found that large increases in installed wind capacity across portfolios had little effect on the capacity requirement for a given security standard, suggesting that wind displaces little conventional capacity. The capacity payments pot remains largely unchanged across the five portfolios, resulting in lower capacity payments per unit of available capacity as wind capacity increases. Under the low demand growth scenario, capacity payments are 9% lower than in the central scenario due to reduced capacity requirements.

The DCENR (2008) study concluded that increased wind generation capacity in portfolios 2 to 5 relative to portfolio 1 would result in fuel cost savings of between 14% and 28%; savings on carbon emissions, except in portfolio 4 which features an additional coal plant; and savings in imported energy across the interconnector. However, these savings are insufficient to compensate for the annualised fixed costs of new renewable capacity and the costs of reinforcing the transmission network. Under the low fuel and carbon price scenario, the CER (2009) study found that the number of unit starts of thermal plants is likely to increase significantly, with implications for recurring maintenance costs and plant life.

6. Results

In this Section we expand on the scenarios presented in Diffney et al. (2009). Specifically, we consider the whole range of assumptions presented in section 4 and their implications for the total cost of meeting electricity demand for the year 2020. We then evaluate the effect for consumers and producers separately and we further decompose the results for producers to analyse the returns to wind generators and all other generators separately. Because of the wide range of different assumptions we simplify the exposition by considering the results across a number of individual dimensions.

In the first case we consider how the total cost of generating electricity is affected by varying the amount of wind generation and the level of interconnection between the Irish and British systems. We do this for medium fuel and carbon prices and for "Adequate" generation in Great Britain. In the second case we consider how varying the assumptions on fuel prices and carbon prices affects the results. Finally we consider how the results would be affected if there is inadequate investment in new generation in Great Britain over the coming decade.

In this Section we expand on the scenarios presented in Diffney et al. (2009). Specifically, we consider the whole range of assumptions presented in section 5 and their implications for the total cost of meeting electricity demand for the year 2020. We then evaluate the effect for consumers and producers separately and we further decompose the results for producers to analyse the returns to wind generators and all other generators separately.

We start by measuring the total system cost of generating electricity with varying amounts of wind generation and levels of electricity interconnection between the Irish and British systems. We assume that most of the new thermal plants commissioned in Ireland are baseload CCGTs and that demand grows at a rate of 1.4 percent per year, in line with the most recent MTR projections (MTR 2008). We then determine how the results change when

1. Assumptions on fuel prices and carbon permit prices vary;
2. There are different power plant portfolios in Ireland and in Great Britain;
3. Demand growth in Ireland is much higher, at 2.7 percent per year.

6.1 Wind and Interconnection effects for different Irish Portfolios

Diffney at al (2009) evaluate the costs and benefits of increasing wind generation both to the system as a whole and to consumers for 2020. They focus on the case where carbon permit prices are set at €38/ton CO_2, Ireland's new thermal plant investment is mainly in CCGTs and Irish demand increases at the lower rate of about 1.4 percent per year out to 2020. The authors find that for a small and isolated electricity system such as Ireland, a high penetration of wind is economically sound only with increased interconnection to Great Britain, since wind generation would otherwise be curtailed. Not surprisingly, for low fuel prices the optimal (least costly) scenario includes low levels of wind generation whereas the opposite is true for high fuel prices.

Table 9. Net system costs, €mill. Difference between CCGT and OCGT portfolio (medium carbon price; low demand; GB as usual)

Wind (MW)	I/C (MW)	Low fuel cost	Medium fuel cost	High fuel cost
		CCGT - OCGT	CCGT - OCGT	CCGT - OCGT
2000	900	-44	-48	-50
	1400	-42	-32	-33
	1900	-39	-22	-25
4000	900	-37	-24	-25
	1400	-37	-24	-27
	1900	-38	-21	-23
6000	900	-27	**9**	**16**
	1400	-22	-12	-13
	1900	-28	-20	-24

Results using the OCGT Irish portfolio under low demand levels show a similar pattern. Low wind capacity and low interconnection provide the smallest net costs under low fuel prices, and high wind capacity and high interconnection the socially optimal solution under medium and high fuel prices. Table 9 shows that for almost all scenarios, the portfolio mix that has a higher share of OCGTs results in higher system costs (a negative sign). This is driven by the lower efficiency of OCGTs with respect to CCGTs and by the fact that in this model CCGTs are almost as flexible as OCGTs in addition to interconnection being implicitly used as an extremely flexible electricity source.

The total societal costs can be decomposed into costs and benefits to consumers, producers and interconnector operators. Increased wind capacity lowers wholesale prices but this is compensated in part by the higher transmission costs incurred when more wind farms are in place (see Table A.1 in the Appendix A). The capacity payments regime as currently calibrated may be unduly favourable to wind generators so that their profits may be greater than would be necessary to fully remunerate their investment. Wind generators in Ireland also currently benefit from the REFIT scheme, which guarantees a minimum price for wind generation, set at €63.7/MWh for on-shore wind in 2008 (DCENR 2009). This cost is recouped through a Public Service Obligation (PSO) paid by all electricity users.

Not surprisingly Table 10 shows that there are decreasing returns to installed wind capacity. The return per MW installed is highest when there are 2000MW of wind and lowest when there are 6000MW of wind. However, with either 4000MW or 6000MW of wind profits per MW increase for wind when interconnection with GB is more extensive. At all levels of wind, wind capacity is remunerated over and above its costs. Note that this is exclusive of possible returns from the REFIT scheme. It therefore appears that there are sufficient incentives for further wind generation. The results are qualitatively similar when the Irish portfolio has a larger share of OCGT natural-gas fuelled plants (see Table A.3 in Appendix A).

Table 10. Average Wind Producer Profit (per MW capacity), €thousands

		Wind Producer Profits per MW capacity, Low demand, CCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Profit	**Δ profit**	**Profit**	**Δ profit**	**Profit**	**Δ profit**
2000	900	97	*highest*	160	*highest*	226	*highest*
	1400	97	0	157	-3	219	-7
	1900	97	0	156	-4	216	-10
4000	900	42	-55	101	-59	155	-71
	1400	46	-51	107	-53	160	-76
	1900	47	*-50*	108	*-52*	161	-77
6000	900	2	-95	46	-112	84	-142
	1400	13	-85	67	-93	109	-117
	1900	19	*-78*	81	*-79*	126	*-100*

Since the All-Island market is a deregulated market it is important to determine if the market provides incentives to invest in new generation. Aggregate generator profits tend to be at their highest for low or medium levels of wind (see Table A.2 in Appendix A). We can also go into a little more detail to determine if wind and thermal generators are affected differently.

Table 11 evaluates the aggregate returns to wind generators from moving from 2000MW of installed wind capacity to 4000MW, or from 4000MW to 6000MW with medium carbon permit prices. For low fuel prices, profits to wind generators as a whole decrease for both options, which means that new wind generation has negative externalities for existing wind. For medium fuel prices profits to wind generators increase when moving up to 4000MW, but decrease when the move is from 4000MW to 6000MW. Finally, high fuel prices provide the best return to new wind investment and in this case profits to wind generators as a whole increase when moving to 6000MW of wind as long as interconnection is not set to 900MW. The results are qualitatively the same if we consider the OCGT portfolio for Ireland (Table A.4 in Appendix A).

Table 11. Change in aggregate wind generator profits, € million. Carbon price: €38/tonne CO_2

		Fuel price		
ΔWind	**I/C (MW)**	**Low**	**Medium**	**High**
From 2000MW to 4000MW	900	-25	85	167
	1400	-11	113	201
	1900	-6	119	212
From 4000MW to 6000MW	900	-155	-133	-118
	1400	-106	-23	17
	1900	-71	54	110

We also evaluate the incentives to invest in thermal generation. Table 12 shows the returns in 2020 to a CCGT plant commissioned in 2010. With medium fuel costs such a plant loses money with either 4000MW or 6000MW of installed wind capacity and higher levels of interconnection. A baseload thermal plant faces reduced profits on the one hand because greater penetration of wind decreases the amount of time the thermal plant runs, but also because at times it is lower in the merit order than imports from Great Britain along the interconnector. With high fuel costs this hypothetical plant is still profitable for 4000MW of wind, but not for 6000MW of wind. These results do not take into account additional maintenance costs to thermal plants that might arise from their increased cycling with large amounts of wind. The results presented here are also limited to a snapshot of 2020 and therefore do not measure actual returns to the investment in the plant over its lifetime. However, these findings suggest that for high levels of wind and interconnection the liberalised market might not provide sufficient incentives for new investment in thermal plants.

Table 12. Returns to baseload CCGT, 10 years old, unit?€ mill?

		Fuel price		
Wind (MW)	**I/C (MW)**	**low**	**medium**	**high**
2000	900	13.2	5.9	8.9
	1400	11.8	1.6	3.6
	1900	11.2	1.2	3.5
4000	900	9.7	2.8	4.9
	1400	9.1	-0.2	1.4
	1900	8.6	-0.4	1.5
6000	900	6.7	0.7	2.4
	1400	6.3	-1.5	-0.3
	1900	6.0	-1.8	-0.2

The results do not change when there is a larger amount of OCGT plants installed (see Table A.5 in Appendix A). In fact Lyons et al. (2007) concluded that with the current regulatory framework OCGTs would on average have lower investment incentives than CCGTs.

Table 13. Exports and Imports. MWh (‘000), low demand, Medium fuel and carbon price

Adequate GB portfolio – CCGT portfolio in Ireland				
Wind (MW)	**I/C (MW)**	**Exports**	**Imports**	**Net Imports**
2000	900	1234.1	1642.7	408.6
	1400	1500.1	2454.2	954.1
	1900	1585.7	3085.3	1499.6
4000	900	1321	1184.7	-136.3
	1400	1935.6	1726.5	-209.1
	1900	2365.5	2204.3	-161.2
6000	900	1082.5	885.6	-196.9
	1400	1724.7	1273.4	-451.3
	1900	2349	1624.6	-724.4

The interconnector owner obtains revenues that rise as the price difference between electricity at the two nodes of the interconnector increases and as the flow grows. As the interconnector size increases the price difference between the two markets it connects decreases, but flow increases as shown in Table 13 (and in Table A.6 in Appendix A when the Irish portfolio has more OCGT plants). There are decreasing returns to interconnection, as shown in Diffney at al. (2009) and Malaguzzi Valeri (2009). Profit-maximising interconnector owners will not take into account the positive externalities produced by more interconnection and will therefore tend to invest less than the socially optimal amount. In the simulations presented here, the optimal levels of interconnection for society and for a merchant interconnector operator often do not coincide. Other factors, not explicitly accounted for here, might affect the incentives of a private investor in interconnection. Uncertainty on future fuel prices and the risk of further investment in interconnection will decrease returns on interconnection and therefore lead to smaller investments. These results hold independent of the portfolio mix in the All-Ireland market. Table A.7 and Table A.8 in Appendix A shows that with large amounts of installed wind capacity merchant interconnectors will underinvest for all levels of fuel prices considered in this study.

Diffney at al. (2009) also determine that system-wide emissions decrease with more wind capacity, as expected. They also decrease with more interconnection when fuel prices are medium or high since in this case there are increased imports from GB. Under current international climate policy countries are only responsible for emissions from productive activity that takes place within their jurisdiction, so we assume here that the Island of Ireland is not responsible for British emissions even though it imports British electricity. This analysis in fact underestimates global emission savings induced by more wind generation since wind generation displaces electricity imports from Great Britain. Again, the same pattern is displayed when the Irish system has a larger share of OCGTs (see Table A.9 in Appendix A). The lower efficiency of the OCGT plants leads to higher SMPs in the OCGT portfolio than the CCGT portfolio, meaning lower exports and higher imports across the interconnector, and consequently lower emissions in the OCGT portfolio. Interconnection is assumed to be perfectly flexible so in these calculations it is always better than OCGT plants at balancing the ups and downs of wind. Emissions reported here include carbon dioxide emissions from fuel use, but not oxides of nitrogen (NO_X) or sulphur dioxide (SO_2) emissions. In particular we do not consider the fact that, in order to accommodate wind, thermal plants may be ramped up and down more often. Denny and O'Malley (2006) find that increasing wind capacity is unlikely to decrease the level of NO_X emissions in Ireland and will only decrease SO_2 emissions if coal generation diminishes. As reference, carbon dioxide emissions from electricity generation in 2007 were about 15 million tonnes (EPA 2009).

In this paper we also give indicative emission figures for the combined region of Ireland and Great Britain. The results should be interpreted as approximate since the GB model we use here is a simplified version of the electricity market in Britain. While greater interconnection reduces Irish emissions in almost every scenario, Table 14 reports higher emissions for increased interconnection when there is low wind capacity on the All-Island system. This arises because the greater interconnector capacity allows Irish demand to be met by cheaper but dirtier plants in Great Britain instead of more expensive but cleaner plants in Ireland. The lowest emission levels for the combined markets occur with 6000MW of wind capacity in Ireland, but with only 900MW of interconnection, unlike the All-Island emissions shown in Diffney at al (2009), which are at a minimum with 1900MW of interconnection in medium and high fuel price scenarios. On average British electricity has a higher carbon dioxide content due to its larger share of coal plants. If the goal is to minimise system-wide emissions, occasionally curtailing Irish wind and not allowing increased generation in GB would achieve that objective. This of course would come at a high cost to the Irish electricity system and eventually to consumers. The same results hold if Ireland has a portfolio with a greater number of OCGT plants (Table A.10 in Appendix A).

Table 14. Combined emissions of British Isles, million tonnes CO2, Irish CCGT portfolio

Wind (MW)	I/C (MW)	Low demand, medium carbon cost					
		Low fuel cost		Medium fuel cost		High fuel cost	
		Emissions	Δ Emissions	Emissions	Δ Emissions	Emissions	Δ Emissions
2000	900	120.2	3.6	229.7	4.7	229.7	4.7
	1400	122.1	5.5	231.1	6.1	231.1	6.1
	1900	124.2	7.6	232.5	7.5	232.5	7.5
4000	900	118.7	2.1	227.6	2.6	227.6	2.6
	1400	120.8	4.2	229	4	229	4
	1900	122.8	6.2	230.4	5.4	230.4	5.4
6000	900	116.6	*lowest*	225	*lowest*	225	*lowest*
	1400	118.5	1.9	226.3	1.3	226.3	1.3
	1900	120.3	3.7	227.6	2.6	227.6	2.6

Wind Curtailment, shown in Figure 2, only occurs when large amounts of wind are installed on the All-Island system. At lower levels, whatever wind-generated energy cannot be dispatched locally can be exported across the interconnector to Great Britain, leading to extremely low curtailment levels with 4000MW installed and none with 2000MW installed. As interconnection provides an outlet for this excess electricity, it is no surprise that larger interconnectors result in less curtailment. Wind is curtailed to a lesser extent under the OCGT portfolio than the less flexible CCGT portfolio resulting in a correspondingly lower loss of revenue.

Figure 2. Wind Curtailment, 6000MW wind, CCGT and OCGT

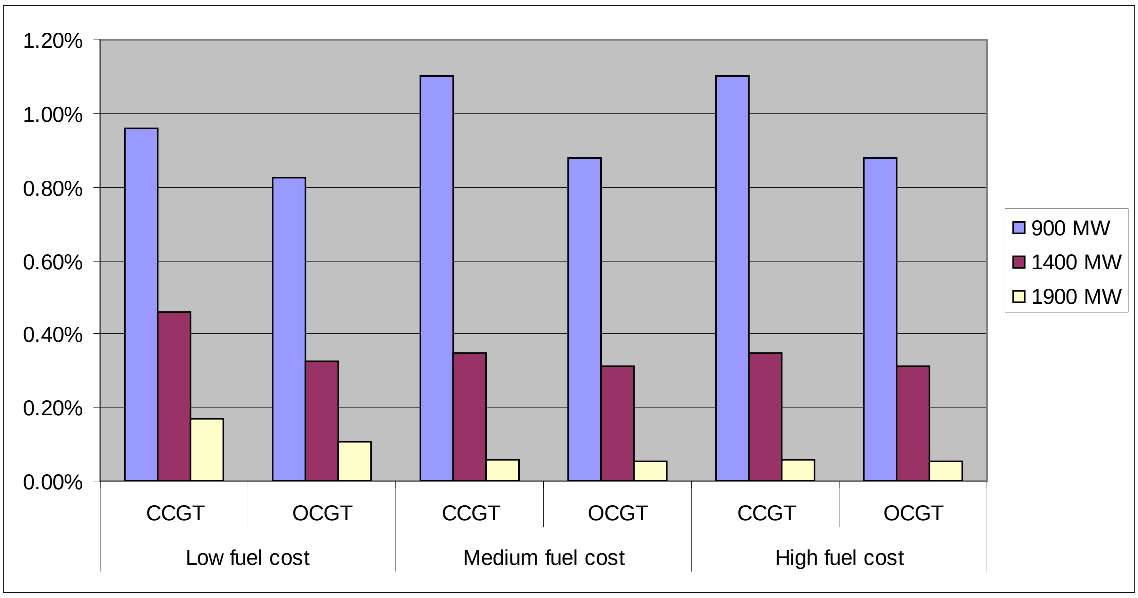

Figure 3 shows how the reliance on natural gas generation decreases when more wind and interconnection are put in place. Net imports also decrease with more wind capacity. The pattern is not much different when the Irish portfolio has a greater number of OCGT plants (see Figure A.1 in Appendix A).

Figure 3. CCGT fuel shares in demand, medium fuel prices.

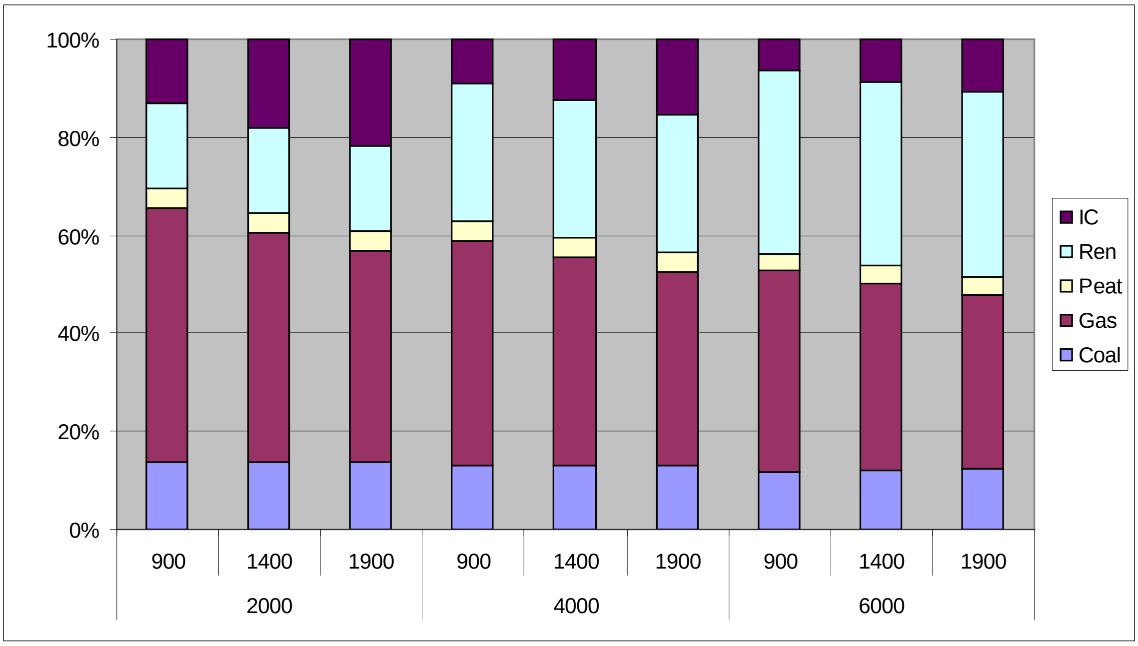

Table 15 reports that with medium fuel prices the CCGT portfolio delivers lower total costs than the OCGT portfolio, regardless of wind capacity or interconnection. The single exception to this is 6000MW wind with 900MW interconnection, which leads to very large additional costs over the cheapest option under both portfolios. We should reiterate that we are underestimating the advantage of OCGTs in this analysis since we are assuming a high flexibility of baseload plants (at least above their minimum stable capacity) and no ramping costs.

Table 15. Comparison of costs under CCGT and OCGT portfolios, € million

		Low demand, Medium fuel prices			
Wind (MW)	**I/C (MW)**	**Consumer costs per MWh**	**Producer Profits**	**Interconnector Profits**	**Total Costs**
		CCGT - OCGT	**CCGT - OCGT**	**CCGT - OCGT**	**CCGT - OCGT**
2000	900	-2.3	-38	-19.3	-48
	1400	-1.2	-2	-20.7	-32
	1900	-0.5	19	-18.6	-22
4000	900	-1.4	-32	-11.7	-24
	1400	-0.8	4	-14.0	-24
	1900	-0.3	20	-14.0	-21
6000	900	-1.1	-52	-8.7	**9**
	1400	-0.5	-2	-10.4	-12
	1900	-0.3	19	-11.3	-20

6.2. Wind and interconnection effects for different carbon costs (assuming CCGT portfolio in Ireland)

Costs and benefits to consumers and producers vary with both fuel prices and carbon prices. As shown in Table 16, the effect of a change in carbon prices on system costs is qualitatively similar to that of a change in fuel prices. In this specific study the effect is smaller when carbon permit prices change than when prices change, but that is due to the specific fuel and carbon assumptions used. When carbon prices are low (with medium fuel) the lowest system costs are attained with 4000MW wind and 1400MW interconnection (see Table 16).

Table 16. Total system cost for different carbon prices, € million, medium fuel prices.

Wind (MW)	I/C (MW)	Low Demand, CCGT portfolio					
		Low carbon cost		Medium carbon cost		High carbon cost	
		Net cost	Δ cheapest	Net cost	Δ cheapest	Net cost	Δ cheapest
2000	900	3243	18	3595	104	4007	146
	1400	3226	1	3577	87	3998	137
	1900	3227	2	3582	91	4008	147
4000	900	3246	21	3541	51	3931	70
	1400	3225	*lowest*	3515	24	3893	32
	1900	3234	9	3522	32	3887	26
6000	900	3429	204	3698	207	4056	195
	1400	3306	81	3561	70	3925	64
	1900	3248	23	3491	*lowest*	3861	*lowest*

For higher carbon permit prices, the minimum system cost is reached when there are 6000MW of wind and 1900MW of interconnection. Consumer costs are minimized with 2000MW of wind and 1900MW of interconnection, although the difference in consumer costs across the various scenarios is minimal (see **Error! Not a valid bookmark self-reference.**).

Table 17. Consumer costs for medium fuel prices, €/MWh, different carbon prices.

Wind (MW)	I/C (MW)	Medium fuel prices, Low demand, Irish CCGT portfolio					
		Low carbon cost		Medium carbon cost		High carbon cost	
		Net cost	Δ costs[a]	Net cost	Δ costs[a]	Net cost	Δ costs[a]
2000	900	90.4	2.6	97.2	2.8	107.2	2.5
	1400	88.7	0.9	95.4	1	105.6	0.9
	1900	87.8	*lowest*	94.4	*lowest*	104.7	*lowest*
4000	900	89.9	2.1	96.6	2.2	106.7	2

	1400	88.8	1	95.4	1	105.6	0.9
	1900	88.2	0.4	94.7	0.3	105	0.3
6000	900	89.6	1.8	96.3	1.9	106.4	1.7
	1400	88.8	1	95.4	1	105.6	0.9
	1900	88.3	0.5	94.8	0.4	105	0.3

[a] Difference with respect to cheapest option

Table 18. Total system costs for different carbon prices, € million, low fuel prices

Wind (MW)	**I/C (MW)**	**Net costs, Low Demand, Low fuel prices, CCGT portfolio**					
		Low carbon cost		**Medium carbon cost**		**High carbon cost**	
		Net cost	**Δ cheapest**	**Net cost**	**Δ cheapest**	**Net cost**	**Δ cheapest**
2000	900	2364	*lowest*	2708	*lowest*	3104	42
	1400	2376	12	2724	16	3124	62
	1900	2396	32	2750	42	3149	87
4000	900	2461	97	2743	35	3062	*lowest*
	1400	2463	99	2749	41	3066	4
	1900	2480	116	2770	62	3084	22
6000	900	2670	306	2892	184	3188	126
	1400	2639	275	2846	138	3136	74
	1900	2627	263	2831	123	3111	49

When fuel costs are low wind is economically less valuable and the minimum system costs occurs for lower wind and interconnection levels, as shown in

Table 18. When fuel costs are high the minimum cost is reached with high levels of wind and interconnection independent of the carbon permit price (see Table 19).

The results reported here suggest that wind capacity and interconnection have an additional benefit. Increased wind and interconnection capacity can be used to hedge against high fuel and carbon prices. Consider the case where carbon permit prices are at €38/tonne CO2 (their medium level). Investing in 6000MW of wind and 1900MW of interconnection brings system costs to €2831 million, an increase of €123 million with respect to the lowest achievable cost (obtained for 2000MW of wind and 900MW of interconnection). If on the other hand fuel costs are medium or high 6000MW of wind and 1900MW of interconnection is the least costly combination. The extra cost of the high wind and interconnection option under the low fuel price scenario can be compared to the extra costs the system would have to bear if only 2000MW of wind and 900MW of interconnection had been commissioned and fuel prices ended up being higher than expected. With medium fuel prices system costs would be €3595 million, €104 million higher than they would be with 6000MW of wind and 1900MW of interconnection. With high fuel prices the system costs would be €311 higher in this case. Which option is ex-ante best depends on the policy makers' expectations of the fuel price level and volatility.

Table 19. Total system costs for different carbon prices, high fuel prices

Wind (MW)	I/C (MW)	Net costs, Low Demand, High fuel prices, CCGT portfolio					
		Low carbon cost		Medium carbon cost		High carbon cost	
		Net cost	Δ cheapest	Net cost	Δ cheapest	Net cost	Δ cheapest
2000	900	4132	202	4483	311	4904	439
	1400	4091	161	4442	270	4863	398
	1900	4074	144	4428	256	4853	388
4000	900	4045	115	4340	168	4694	229
	1400	4008	78	4296	124	4644	179
	1900	4008	78	4296	124	4643	178
6000	900	4198	268	4467	295	4791	326
	1400	4016	86	4270	98	4576	111
	1900	3930	*lowest*	4172	*lowest*	4465	*lowest*

Table 20 shows that increasing wind capacity to 4000MW increases aggregate profits for wind generators as a whole independent of the level of carbon permit prices. Decreasing returns eventually kick in and a further growth to 6000MW of wind decreases aggregate profits for wind generators as a whole when carbon permit prices are low. When carbon permit prices are medium or high, aggregate wind generator profits increase if interconnection is at its highest, at 1900MW. This is in line with the results shown in Table 11, where we considered different levels of fuel prices and kept carbon prices fixed at €38/tonne CO_2, their medium level.

Table 20. Change in aggregate wind generator profits, € million; medium fuel price

ΔWind	I/C (MW)	Carbon permit price		
		Low	Medium	High
From 2000MW to 4000MW	900	33	85	115
	1400	57	113	156
	1900	64	119	175
From 4000MW to 6000MW	900	-161	-133	-96
	1400	-68	-23	2
	1900	-3	54	62

Table 21 shows that the returns to a hypothetical new thermal plant built in 2010 with different carbon permit prices also display the same pattern as the returns with different fuel prices (see Table 12).

Once installed wind generation reaches 4000MW returns to this CCGT plant go below zero when carbon prices are either at a low or medium level. The costs to the plant are likely to be understated in this simulation since they do not include the additional maintenance costs of cycling the plant to follow changes in wind generation.

When carbon prices are high profitability increases again. This is due to net imports from Great Britain decreasing in this case.

Table 21. Returns to 10 year old CCGT plant, € mill; medium fuel price

		Carbon permit price		
Wind (MW)	**I/C (MW)**	**low**	**medium**	**high**
2000	900	5.5	5.9	13.0
	1400	1.6	1.6	9.7
	1900	1.4	1.2	8.9
4000	900	2.6	2.8	9.7
	1400	0.0	-0.2	7.6
	1900	-0.1	-0.4	6.7
6000	900	0.7	0.7	7.3
	1400	-1.4	-1.5	5.7
	1900	-1.5	-1.8	4.5

Table 22 shows how imports and exports change for different carbon permit prices when fuel prices are at their medium level. As carbon prices increase imports from Great Britain decrease since British generation is more coal-intensive and therefore becomes relatively more expensive. Net imports decrease with high carbon costs, since at that point the British coal plants become more expensive. Net imports also decrease with higher wind capacity since exports increase in those scenarios.

Table 22. Net imports (,000 MWh); low demand, medium fuel price

Wind (MW)	**I/C (MW)**	**Low carbon cost**	**Medium carbon cost**	**High carbon cost**
2000	900	5432	5718	2837
	1400	7586	8017	4021
	1900	9242	9753	5013
4000	900	2437	2742	202
	1400	3764	4195	435
	1900	5096	5597	854
6000	900	-18	256	-1769
	1400	282	661	-2417
	1900	966	1407	-2690

6.3. Wind and interconnection effects for different GB Portfolios

Up to now increased interconnection appears on average to decrease both Irish system costs and costs to consumers under a variety of fuel and carbon permit prices. We are interested in exploring what would happen if the generating portfolio mix were to change in Great Britain. Specifically, we examine the case where Great Britain encounters planning difficulties and therefore new coal-fired plants are not built in time to replace coal plants closed because of the Large Combustion Plant Directive. CCGT plants are assumed to be built instead since they are relatively quick to build and have a mature technology. Ireland maintains its CCGT-intensive portfolio for all the scenarios presented in this section and Irish demand growth is low.

Table 23 below shows the difference that moving to this new GB portfolio has on the Irish system. We find that the effect on the Irish market is mixed: planning difficulties in the British market, which would lead to more CCGT plants being required, would result in lower overall system costs for Ireland when 4000MW or 6000MW of wind are installed. Producers' profits are higher in all circumstances under the GB CCGT portfolio, but the wholesale cost of electricity is also higher and interconnector profits are lower across the board. With a larger share of CCGT plants the GB system becomes more similar to Ireland's and the price differential between the two systems decreases, a main determinant of lower interconnector profits.

Table 23. Irish costs and benefits with GB CCGT – Irish costs and benefits with adequate GB portfolio, €mill.

Low demand, Medium fuel and carbon price					
Wind (MW)	**I/C (MW)**	**Total Costs €mill.**	**Consumer Costs/MWh €,000**	**Producer profits €mill.**	**IC benefits €mill.**
2000	900	3.2	0.5	26.2	-10.4
	1400	6.9	0.5	35.3	-15.3
	1900	7.8	0.6	41.1	-19.4
4000	900	-8.6	0.3	36	-10.3
	1400	-18	0.5	52.2	-12
	1900	-18.7	0.6	58.2	-12.3
6000	900	-2.9	0.3	29.1	-12.6
	1400	-15	0.4	50.2	-16.7
	1900	-28.7	0.5	68.7	-17.1

The use of gas rather than coal in this GB portfolio makes British electricity more expensive relative to Irish electricity, greatly increasing Irish exports across the interconnector and reducing imports.

Table 24. Change in emissions: (CCGTs Used in GB - Adequate GB portfolio), mill. tonnes of CO_2

Low Irish demand, Medium fuel price				
Wind (MW)	**I/C (MW)**	**AI Emissions**	**GB Emissions**	**Combined Emissions**
2000	900	1.1	-16	-14.9
	1400	1.4	-16.6	-15.2
	1900	1.7	-17.2	-15.5
4000	900	1	-15.4	-14.4
	1400	1.4	-16	-14.6
	1900	1.7	-16.4	-14.7
6000	900	0.7	-14.8	-14.1
	1400	1.1	-15.2	-14.1
	1900	1.5	-15.5	-14

Emissions from the All-Island market increase as a consequence of the increased exports. The British CCGT plant portfolio is cleaner than the coal-intensive alternative so British emissions drop by more than the Irish increase resulting in a net decrease in carbon dioxide emissions for the British Isles from the CCGT portfolio.

Finally, the higher exports to Great Britain lead to more plants being used in Ireland. As the marginal plant on the Irish system is generally gas, this increase in load leads to a higher output of gas plants, pushing up the share of demand met by gas, with all other fuels decreasing their market share. Combining this with the increased British reliance on gas under the CCGT portfolio suggests that this scenario might be undesirable from a security of supply perspective.

Table 25. Change in Share of Demand: (CCGTs Used in GB - Adequate GB portfolio), % points

Low demand, Medium fuel price, medium carbon price						
Wind (MW)	**I/C (MW)**	**Coal**	**Gas**	**Peat**	**Renewables**	**Imports**
2000	900	-0.3	+4.6	-0.1	-0.4	-3.8
	1400	-0.4	+6.7	-0.1	-0.5	-5.7
	1900	-0.4	+8.2	-0.2	-0.6	-7
4000	900	-0.3	+3.8	-0.1	-0.7	-2.6
	1400	-0.4	+5.6	-0.2	-1.1	-3.9

	1900	-0.6	+7.2	-0.2	-1.3	-5.1
6000	900	-0.2	+3	-0.1	-0.8	-1.9
	1400	-0.4	+4.6	-0.1	-1.3	-2.8
	1900	-0.5	+6	-0.2	-1.7	-3.6

Aggregate wind generator profits increase moving from 2000MW to 4000MW of wind, whereas they decrease when going from 4000MW to 6000MW of wind, unless interconnection increases to 1900MW. Table 26 shows that the pattern is the same when GB is modelled with the existing portfolio (BAU) or if we assume a greater penetration of gas-fired plants (CCGT).

Table 26.Change in aggregate wind generator profits, € million; medium fuel and carbon price

		Change in wind profits		
ΔWind	**I/C (MW)**	**GB BAU**	**GB CCGT**	**GB CCGT – GB BAU**
From 2000MW to 4000MW	900	85	96	11
	1400	113	132	19
	1900	119	139	20
From 4000MW to 6000MW	900	-133	-136	-3
	1400	-23	-22	-1
	1900	54	67	13

When Great Britain has a larger proportion of baseload gas-fired plants a hypothetical 10 year old CCGT plant installed in Ireland fares slightly better than in the alternative scenario (compare with Table 12). As seen in Table 27, it has negative returns only in the medium fuel price scenario when there are 6000MW of wind and a high level of interconnection with Great Britain.

Table 27. Returns to 10 year old CCGT plant, € mill; medium fuel price, medium carbon price

		fuel price		
Wind (MW)	**I/C (MW)**	**low**	**medium**	**high**
2000	900	11.2	6.5	9.6
	1400	8.4	2.8	5.1
	1900	7.1	3.6	6.7
4000	900	7.7	3.3	5.5
	1400	6.1	0.8	2.6
	1900	5.1	1.7	4.2
6000	900	5.0	1.1	2.9
	1400	3.8	-0.8	0.7
	1900	3.0	-0.1	2.1

6.4. Wind and interconnection effects for higher Irish growth rate

In this section we analyse how the results change when Irish demand is assumed to increase at the higher rate of about 2.7 percent per year instead of 1.4 percent. This allows us to compare our results with those of the AIGS and the CER papers. Costs to the system are naturally higher. In addition to the increased fuel and carbon emission permits used by existing plants, there are also additional plants on the system to maintain system reliability.

Table 28. Net costs of Irish electricity system when carbon permits = €38/tonne, 2020, € million

Wind (MW)	I/C (MW)	Low fuel cost		Medium fuel cost		High fuel cost	
		Net cost	Δ cheapest	Net cost	Δ cheapest	Net cost	Δ cheapest
2000	900	3235.9	*cheapest*	4327.2	164.2	5421.6	389.7
	1400	3244.8	8.9	4286.9	123.9	5348.0	316.2
	1900	3267.1	31.2	4280.6	117.6	5324.3	292.5
4000	900	3249.2	13.4	4230.9	67.8	5224.4	192.5
	1400	3257.0	21.1	4205.1	42.0	5180.8	149.0
	1900	3278.4	42.6	4210.5	47.4	5178.5	146.6
6000	900	3351.8	116.0	4300.7	137.7	5227.9	196.1
	1400	3325.1	89.2	4206.3	43.2	5092.4	60.6
	1900	3320.1	84.3	4163.1	*cheapest*	5031.8	*cheapest*

Table 28 shows results that are in line with the findings of the AIGS and CER. For medium or high fuel costs the option with 6000MW of wind (and 1900MW of interconnection) is the cheapest. With medium fuel costs the system with 4000MW of wind has similar costs to the system with 6000MW of wind.

Returns to wind and thermal plant investors improve thanks to the higher demand, despite the fact that there are more fossil fuelled plants on the system. Comparing Table 11, calculated for the base scenario of low demand, and Table 29 shows that the returns to wind generation as a whole grows more (or decreases less) when moving to higher levels of wind when electricity demand growth is more sustained.

Table 29. Change in aggregate wind generator profits, € million; high demand, medium carbon price

ΔWind	I/C (MW)	Fuel price		
		low	medium	high
From 2000MW to 4000MW	900	-11	108	198
	1400	-2	121	214
	1900	1	124	220

	900	-115	-59	-16
From 4000MW to 6000MW	1400	-81	16	74
	1900	-55	68	136

Table 30. Returns to 10 year old CCGT plant, € mill; medium carbon price

		fuel price		
Wind (MW)	**I/C (MW)**	**low**	**medium**	**high**
2000	900	14.2	8.2	11.9
	1400	12.2	3.5	6.0
	1900	11.2	0.2	2.1
4000	900	10.6	4.3	6.8
	1400	9.5	1.1	3.0
	1900	8.8	-1.3	0.2
6000	900	7.6	2.0	4.0
	1400	7.0	-0.5	1.0
	1900	6.4	-2.6	-1.2

Comparing Table 12 to Table 30 shows that returns are higher for a hypothetical 10 year old CCGT plant with higher demand than with lower demand, despite the fact that with higher demand there will be two additional (and more efficient) baseload natural gas fuelled plants on the system (see Table 2). It is still true, however, that at high amounts of wind and interconnection, a 10-year old natural gas fuelled plant is squeezed out, leading it to sustain negative returns on its investment in 2020.

7. Conclusions

- The results from this study generally confirm the results from DCENR(2008) and CER (2009).
- As in Diffney *et al.* (2009) more wind up to 6000 MW is good for consumers and for the economy with medium or high fuel prices. Similar results hold where carbon prices are high.
- More wind is only good if combined with 1900 MW of interconnection.

- The cost of over investing in wind when fuel prices are low is more than counterbalanced by the higher cost of not investing in wind when fuel prices are high. This illustrates how investment in renewables can provide a hedge against high fuel prices (see FitzGerald et al., 2006).
- The incentives for investment in wind provided by the market are at least adequate to ensure the necessary investment to reach the 40% renewables target.
- However, there are concerns that revenues to fossil-fuelled plants might not be adequate to sustain investment in a deregulated market. Further analysis of this issue is needed.
- These results suggest that there may be a need to re-examine the way that wind is remunerated under the system.

In the case of a failure to invest in new coal or nuclear plant in GB over the coming decade the effects on the Irish system would be:

- Producers' profits are higher in all circumstances under this scenario as the wholesale cost of electricity is higher. This is clearly undesirable from the point of view of Irish consumers. Interconnector profits are lower under this scenario.
- Emissions from the All-Island market would increase as a consequence of the increased exports. The British CCGT plant portfolio is cleaner than the coal-intensive alternative so British emissions drop by more than the Irish increase resulting in a net decrease in carbon dioxide emissions for the British Isles from the CCGT portfolio.
- The higher exports to Great Britain lead to more plants being utilised in Ireland. As the marginal plant on the Irish system is generally gas, this increase in load leads to a higher output of gas plants, pushing up the share of demand met by gas, with all other fuels decreasing their market share. Combining this with the increased British reliance on gas under the CCGT portfolio suggests that this scenario might be undesirable from a security of supply perspective for the British Isles as a whole.
- When electricity demand growth is higher, system costs are not surprisingly higher and returns to generators tend to increase as well. This highlights the added uncertainty risk surrounding electricity demand growth. Investing for higher growth when in fact it will be lower means higher than necessary costs for consumers. On

the other hand the risks of underinvesting would also be borne by consumer in the form of reduced system reliability.

There are a few caveats to the findings.

This is a static model, looking at results only for the year 2020. Results may change over time and ideally one would look at average results over the lifetime of plants. This implies setting up a dynamic model of investment.

We assume that interconnection is used efficiently and electricity flows whenever there is a difference in price between the two jurisdictions. In practice we assume that markets are coupled and that interconnection behaves exactly like any other type of transmission. If there are transaction costs the utilisation rate of the interconnector would decrease, leading to lower benefits of high levels of wind.

We also abstract from possible negative environmental externalities of wind, be they due to visual disamenities or the fact that some wind farms might be built on intact peat land (which would lead to higher emissions of carbon dioxide in the atmosphere). We also limit the effect of wind on thermal plants by not fully accounting for the cost of cycling on thermal plants.

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Appendix A. Additional results for low demand growth

This section presents results for the low demand growth scenario with the OCGT Irish generation portfolio. As discussed previously, the OCGT portfolio results in higher net system costs in almost all combinations of fuel price, wind capacity and interconnection. Table A.1 illustrates some of the differences between the two portfolios. First, under high fuel prices the lowest consumer costs are obtained with 6000MW of wind and 1900MW of interconnection. This seems to be a big change from the CCGT portfolio, in which the optimal costs come with 2000MW of wind. However, it is clear from the table that the actual difference in cost between the two wind capacities is very small, so this does not represent a major change in system behaviour. Consumer costs are consistently, albeit slightly, higher under the OCGT portfolio than the CCGT portfolio, and the reaction to changes in wind capacity and interconnection are very similar to those for the CCGT portfolio.

Table A.1. Consumer costs, €mill. (medium carbon price; low demand, OCGT portfolio, GB as usual)

		Low demand, OCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Net cost	**Δ costs[a]**	**Net cost**	**Δ costs[a]**	**Net cost**	**Δ costs[a]**
2000	**900**	73.5	2.5	99.5	4.6	130.8	6.3
	1400	72.4	1.4	96.6	1.7	126.8	2.3
	1900	71.9	0.9	94.9	*cheapest*	124.6	0.1
4000	**900**	72.5	1.5	98	3.1	128.5	4
	1400	71.9	0.9	96.2	1.3	126	1.5
	1900	71.6	0.6	95	0.1	124.6	0.1
6000	**900**	71.7	0.7	97.4	2.5	127.4	2.9
	1400	71.2	0.2	95.9	1	125.6	1.1
	1900	71	*cheapest*	95.1	0.2	124.5	*cheapest*

As with consumer costs, the only change in optimal portfolios for producers is the result of a small change in relative profits between 4000MW wind with 900MW interconnection, and the CCGT optimum of 6000MW wind with 1900MW interconnection. Similar to the results found with the CCGT portfolio, the cost to producers of selecting the wrong level of wind or interconnection in the OCGT portfolio is proportionately much greater than the cost to the consumer.

Table A.2. Producer profits, €mill. (medium carbon price; low demand, OCGT portfolio, GB as usual)

		Low demand, OCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Net benefits	**Δ benefits**	**Net benefits**	**Δ benefits**	**Net benefits**	**Δ benefits**
2000	**900**	610	*highest*	885	-27.3	1372	-77.6
	1400	557	-53.4	781	-130.8	1228	-221.9
	1900	534	-75.7	722	-189.7	1149	-300.7
4000	**900**	542	-67.7	912	*highest*	1450	*highest*
	1400	518	-92.3	853	-58.5	1368	-81.4
	1900	503	-107.3	813	-98.6	1320	-129.4
6000	**900**	359	-251.2	759	-153	1294	-155.7
	1400	393	-217	808	-104.3	1348	-101.7
	1900	410	-199.7	842	-69.6	1392	-57.9

Looking at the profitability of wind producers per capacity installed, we again see that increasing interconnection leads to lower system costs, which reduces profits to wind when there is little capacity installed. With more wind installed, more interconnection leads to less curtailment, so profitability increases. Overall profit levels depend on both interconnection and particularly fuel costs (Table A.3), with 2000MW returning the highest profits when fuel prices are low, and 6000MW when fuel prices are higher, provided there is sufficient interconnection to take advantage of price differences without requiring excessive curtailment of wind.

Table A.3. Average Wind Producer Profits (per MW capacity), € thousand

		Low demand, OCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Profits	**Δ Profits**	**Profits**	**Δ Profits**	**Profits**	**Δ Profits**
2000	**900**	100	max profits	165	max profits	234	max profits
	1400	98	-2	159	-6	222	-12
	1900	97	-3	156	-9	217	-17
4000	**900**	46	-3	106	-2	162	0

	1400	48	-1	108	0	162	max profits
	1900	49	max profits	108	max profits	161	-1
6000	**900**	6	-16	53	-28	94	-32
	1400	17	-5	70	-11	113	-13
	1900	22	max profits	81	max profits	126	max profits

Table A.4. Difference for aggregate wind generator profits, € million. Carbon prices €38/tonne CO_2

		Fuel price		
ΔWind	**I/C (MW)**	**Low**	**Medium**	**High**
From 2000MW to 4000MW	900	-18	94	177
	1400	-4	114	203
	1900	-1	119	212
From 4000MW to 6000MW	900	-147	-112	-90
	1400	-93	-10	34
	1900	-61	53	108

Table A.5. Annual returns to baseload CCGT, 10 years old

		Fuel price		
Wind (MW)	**I/C (MW)**	**low**	**medium**	**high**
2000	900	13.2	5.9	8.9
	1400	11.8	1.6	3.6
	1900	11.2	1.2	3.5
4000	900	9.7	2.8	4.9
	1400	9.1	-0.2	1.4
	1900	8.6	-0.4	1.5
6000	900	6.7	0.7	2.4
	1400	6.3	-1.5	-0.3
	1900	6.0	-1.8	-0.2

Table A.6. Exports and Imports (million MWh). Low demand, OCGTs, GB as usual.

Wind (MW)	I/C (MW)	Low demand, OCGT portfolio								
		Low fuel cost			Medium fuel cost			High fuel cost		
		Exports	**Imports**	**Net Imports**	**Exports**	**Imports**	**Net Imports**	**Exports**	**Imports**	**Net Imports**
2000	900	0.9	4.9	4	0.1	6.7	6.6	0.1	6.7	6.6
	1400	1.1	6.3	5.2	0.2	9.5	9.3	0.2	9.5	9.3
	1900	1.1	6.7	5.6	0.2	11.5	11.3	0.2	11.5	11.3
4000	900	2.4	3.2	0.8	1.1	5	3.9	1.1	5	3.9
	1400	3.1	3.9	0.8	1.3	6.9	5.6	1.3	6.9	5.6
	1900	3.5	4.1	0.6	1.2	8.3	7.1	1.2	8.3	7.1
6000	900	3.7	2.3	-1.4	2.5	3.7	1.2	2.5	3.7	1.2
	1400	5.2	2.8	-2.4	3.2	5.1	1.9	3.2	5.1	1.9
	1900	6.2	2.9	-3.3	3.4	6.2	2.8	3.4	6.2	2.8

Interconnector profits per MW capacity (Table A.7) are higher under the OCGT portfolio than the CCGT portfolio, by as much as 28% under medium fuel prices, but maximum profits to the interconnector operator are delivered under the same circumstances in CCGT and OCGT portfolios, and profits follow similar patterns in their responses to wind and interconnection

Table A.7. Interconnector profits, €thousand per MW. (medium carbon price; low demand, OCGT portfolio, GB as usual)

Wind (MW)	I/C (MW)	I/C Profits, Low demand, OCGT portfolio					
		Low fuel cost		Medium fuel cost		High fuel cost	
		Profits	**Δ Profits**	**Profits**	**Δ Profits**	**Profits**	**Δ Profits**
2000	**900**	59.9	-0.9	109.6	*highest*	195.1	-5.7
	1400	30.6	-30.2	70.4	-39.2	138.4	-62.4
	1900	10.4	-50.4	44.4	-65.2	101.3	-99.5
4000	**900**	54.9	-5.9	89.9	-19.7	176.7	-24.1
	1400	27.5	-33.3	55.5	-54.1	118.7	-82.1
	1900	8.2	-52.6	32.2	-77.4	80.2	-120.6

6000	**900**	60.8	*highest*	87.9	-21.7	200.8	*highest*
	1400	35.5	-25.3	57.4	-52.2	147.6	-53.2
	1900	15.7	-45.1	34.6	-75	104.8	-96

Table A.8. Total system benefits and interconnector profits, €mill. OCGT scenario

		Low demand, OCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Total Benefit	**IC profits**	**Total Benefit**	**IC profits**	**Total Benefit**	**IC profits**
2000	**900**	*optimal*	*optimal*	-39	0	-80	-18.1
	1400	-14	-11.1	-5	*optimal*	-22	*optimal*
	1900	-37	-34.1	*optimal*	-14.2	*optimal*	-1.2
4000	**900**	*optimal*	*optimal*	-26	*optimal*	-46	-7.2
	1400	-6	-10.9	*optimal*	-3.2	-4	*optimal*
	1900	-28	-33.8	-4	-19.8	*optimal*	-13.8
6000	**900**	-60	*optimal*	-178	-1.3	-255	-26
	1400	-9	-5	-62	*optimal*	-87	*optimal*
	1900	*optimal*	-24.9	*optimal*	-14.6	*optimal*	-7.5

Carbon emissions in the OCGT portfolio (Table A.9 and Table A.10) are similar to those in the CCGT portfolio: increased wind capacity leads to lower carbon emissions, but the lower efficiency of the OCGT plants leads to a higher SMP, and consequently lower exports (Table A.7) and lower emissions for Ireland, but the higher flexibility of OCGT leads to lower overall emissions for the combined market with Great Britain.

Table A.9. All Island carbon dioxide emissions (million tonnes), Low demand, OCGT portfolio

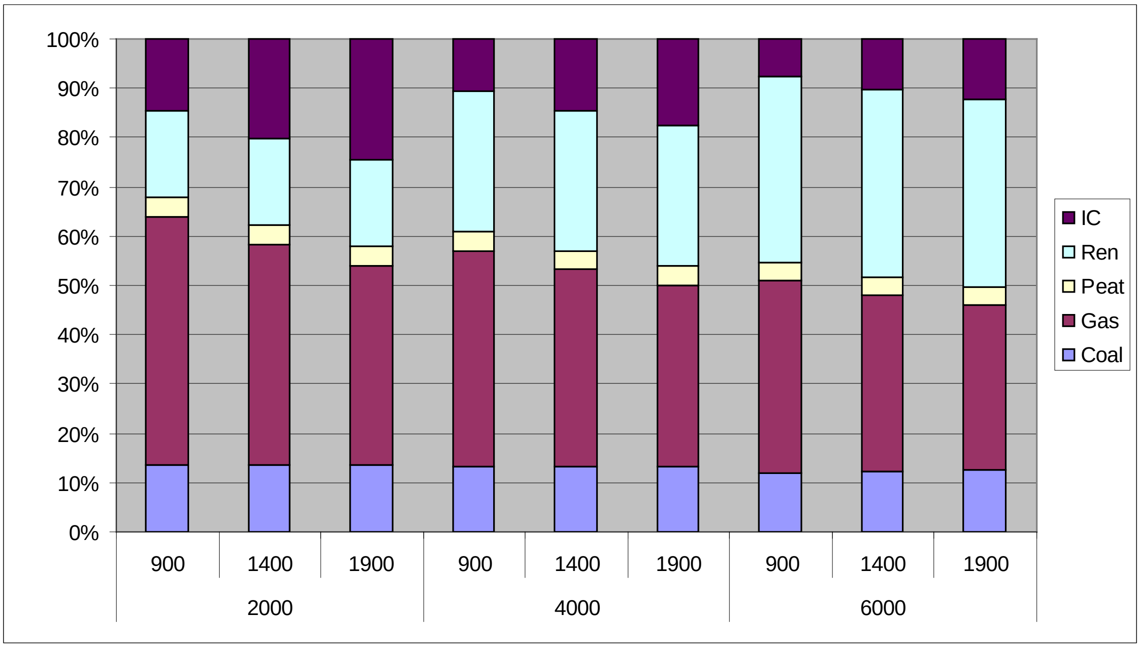
		AI Carbon dioxide Emissions (million tonnes), Low demand, OCGT portfolio					
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Emissions	**Δ Emissions**	**Emissions**	**Δ Emissions**	**Emissions**	**Δ Emissions**
2000	**900**	14.4	2.1	16.6	2.7	16.6	2.7

	1400	13.7	1.4	15.5	1.6	15.5	1.6
	1900	13.5	1.2	14.8	0.9	14.8	0.9
4000	**900**	13.4	1.1	15.5	1.6	15.5	1.6
	1400	13.3	1	14.8	0.9	14.8	0.9
	1900	13.4	1.1	14.3	0.4	14.3	0.4
6000	**900**	12.3	*lowest*	14.4	0.5	14.4	0.5
	1400	12.5	0.2	14.1	0.2	14.1	0.2
	1900	12.8	0.5	13.9	lowest	13.9	*lowest*

Table A.10. Combined emissions of British Isles, million tonnes CO_2, Irish OCGTs.

GB + AI Carbon dioxide Emissions (million tonnes), Low demand, OCGT portfolio							
Wind (MW)	**I/C (MW)**	**Low fuel cost**		**Medium fuel cost**		**High fuel cost**	
		Emissions	**Δ Emissions**	**Emissions**	**Δ Emissions**	**Emissions**	**Δ Emissions**
2000	900	119.7	3.4	229.5	4.5	229.5	4.5
	1400	121.3	5	230.6	5.6	230.6	5.6
	1900	123.3	7	232	7	232	7
4000	900	118.3	2	227.5	2.5	227.5	2.5
	1400	120.2	3.9	228.6	3.6	228.6	3.6
	1900	122.1	5.8	230	5	230	5
6000	900	116.3	*lowest*	225	*lowest*	225	*lowest*
	1400	118.1	1.8	226	1	226	1
	1900	119.8	3.5	227.3	2.3	227.3	2.3

Figure A.1. OCGT fuel shares in demand, medium fuel prices.



Finally, Figure A.1 shows that patterns in fuel consumption across changes in wind and interconnection are very similar for OCGT and CCGT scenarios. However, gas-fuelled generation makes up a slightly smaller share of demand in the OCGT scenario.

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