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Should Coal Replace Coal? Options for the Irish Electricity Market*

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Abstract: The Moneypoint coal plant is nearing the end of its useful life and will need to be replaced. For Moneypoint's replacement, we consider different types of baseload technologies: coal plants with and without carbon capture, combined-cycle gas plants and a nuclear plant. This paper compares how the different types of plant are likely to affect the net costs of the Single Electricity Market under a number of fossil fuel and carbon price scenarios and highlights issues that might be of interest to final consumers and policy makers, namely effects on short-run prices, emissions and energy security.

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Should coal replace coal? Options for the Irish electricity market

1. Introduction

The Irish electricity system will need significant investment in the next couple of decades. A generation of aging plants are set to close, the transmission and distribution systems need reinforcement and carbon dioxide emissions must decrease to comply with EU legislation. This paper focuses on the decommissioning of its largest coal plant, Moneypoint, which is likely to happen around 2025.

The decision on the type of replacement plant will be taken in the context of very uncertain markets, reflecting the volatility of fuel and carbon permit prices, the extent of wind penetration, the amount of interconnection to Great Britain, and the organisation of the British electricity market.

The goal of this paper is to investigate the possible impact of this decision on electricity consumers and on the reliability of the electricity system. We outline what we believe are the most likely technological candidates for replacement and highlight their advantages and disadvantages for the All-Island electricity system. We do not aim to measure the returns to private investors and therefore do not evaluate the likelihood that any of these plants will be built.

The Irish electricity system is part of the deregulated Single Electricity Market (SEM), which includes the jurisdictions of the Republic of Ireland and Northern Ireland. The technologies considered in this study are Combined Cycle Gas Turbines (CCGT), Pulverised Coal (PC) ready to be retrofitted with carbon capture and storage, PC coal plants with carbon capture (CC), retrofit-ready coal plants using the Integrated Gasification Combined Cycle (IGCC) technology, IGCC coal plants built with carbon capture and storage and nuclear plants.

Many studies have compared the cost of each technology on a levelised-cost basis (MIT 2003, IEA 2010). The advantage of the levelised-cost method is that it is a fairly straightforward method that allows clear comparisons of costs across different technological options. The disadvantage is that to compare different technologies the assumption is generally that all the alternative plants run at their maximum possible load (net of necessary maintenance periods). This paper differs from those studies by calculating the costs and benefits of each option on the system as a whole and in particular on the wholesale electricity cost. This method allows us to account for scenarios where baseload plants might not work at full load, which might arise when coal plants operate at times of low natural gas and high carbon dioxide prices.

We find that the optimal technology depends on exogenous factors such as the level of fuel prices and carbon permit prices. In addition, the type of technology chosen will not have an immediate effect on wholesale prices, since the shadow price in 2025 will continue to be set by older natural gas plants.

The next section provides details on the technology options and describes the Irish electricity system. Section 3 introduces the model and the results and section 4 concludes.

2. Background and assumptions

The replacement of Moneypoint will come at a time of large investment in new generation around the world. Despite their environmental drawbacks and high carbon dioxide emission levels, coal plants are being built in large numbers, although almost exclusively in developing countries. In 2009 coal-fired plants generated almost 35 percent of total electricity generation in OECD countries, as shown in Table 1. In addition coal produced about 80 percent of Chinese electricity (IEA 2009a). Coal generation also provided almost 70 percent of Indian electricity.

Table 1. Share of electricity generation by fuel type in OECD countries (%)

	1990	2000	2008	2009
Nuclear	22.5	23.0	20.9	21.4
Hydro	16.0	14.4	12.9	13.2
Geothermal	0.4	0.3	0.4	0.4
Wind	0.0	0.3	1.7	2.1
Coal	40.4	38.7	36.3	34.6
Oil	9.1	6.1	3.7	3.1
Natural Gas	9.9	15.7	21.9	22.6
Comb. Renew. &Waste	1.6	1.5	2.2	2.5
Other	0.0	0.0	0.0	0.1
Total	100	100	100	100

Source: authors' elaboration of data from Table 2.6 in *Electricity Information* (IEA 2011)

Natural gas generation, mostly using baseload combined-cycle gas turbines (CCGT), has been consistently growing in developed countries, doubling its market share from about 10 percent in 1990 to more than 20 percent in 2009.

We also consider the option of building a nuclear plant. As shown in Table 1, the share of electricity generation from nuclear plants has kept up with overall generation growth between 1990 and 2009, equal to 2.1 percent per year (IEA 2011, Table 2.6). Nuclear plants have dramatically improved the percentage of time they are available to generate electricity over time, from an average of 62 percent in the late 1980s to 90.5 percent in 2004 (Hansen and Skinner, 2005). Recent events such as the nuclear emergency declared in Japan after the cooling systems failed at the Fukushima nuclear power plant after the earthquake in March 2011 and the announcement in May 2011 that Germany plans to abandon nuclear energy completely within 11 years mean nuclear power is unlikely to maintain its market share. The low-carbon promise of nuclear technology is still making it attractive to some. India is slated to build about four new plants and has signed an agreement with the French government to facilitate this. Both the United Kingdom and the United States of America are looking to replace aging plants with new ones, although it is unlikely that this will lead to a full 'nuclear renaissance', mostly due to the high economic costs associated with building and running these plants (Joskow and Parsons, 2012).

As with other large infrastructure investments, there are a few well-known challenges when building new generation plants: projects undertaken infrequently tend to be more expensive, since contractors and project managers cannot take advantage of the natural learning curve present in more frequent projects. Building new technologies is consistently associated with cost overruns and delays (Flyvbjerg et al. 2002).

In this section we first introduce the detailed assumptions on each plant's building and operating costs. We then present and discuss the framework under which we measure the costs and benefits to the system. This study evaluates the average annual costs of producing electricity in the year 2025. We assume that electricity demand in 2025 is 9 percent higher than in 2008. This is consistent with the 2020 electricity demand in the SEAI Baseline scenario (SEAI, 2011).

Costs are presented in 2008 euro. Each study calculates plant operation and maintenance (O&M) costs differently, splitting the costs between variable and fixed O&M costs. In order to be consistent across technologies and separate studies, all the O&M costs used here are measured on an annual basis. To maintain consistency between different sources of cost data, costs are first inflated to 2008 USD, using the consumer price index for the United States, then transformed into 2008 Euro at the average exchange rate for 2008.

Table 2 summarises costs and construction times for each plant we analyse. The costs include the initial construction costs, the yearly operation and maintenance (O&M) costs and the decommissioning costs. Table 2 also presents the assumptions used for the lifetime of the plant, the efficiency (how much of the primary energy used is converted into electricity) and the typical yearly plant availability, net of expected maintenance days, in addition to the assumed cost of capital for the simulation analysis, which is 8% for all plants except nuclear. The weighted average cost of capital (WACC) for a nuclear power station has been set at 11.5%, in line with MIT (2003). The inflation rate is assumed to be 2% each year out to 2025. Loans are fully repaid after 15 years, but the annual cost is spread over the whole life of the asset.

Table 2 Construction times and cost assumptions, 2008 euro, for 1000MW

	Coal, PC	Coal, IGCC	Coal, PC w/CCS	Coal, IGCC w/CCS	Natural Gas CCGT	Nuclear
Construction time (years)	4	4	4	4	2	7
Weighted Average Cost of Capital %	8	8	8	8	8	11.5
Overnight cost (€/kW)[a]	1408	2447	3644	3466	727	3500
includes building contingency of	5%	13%	15%	15%	5%	15%
Lifetime of plant (years)	40	40	40	40	25	40
Yearly capital cost for 1000MW (million euro)	62.3	108.3	161.3	153.4	48.5	237.8[c]
Fixed O&M costs (€/kW/year)	62	90.4	112.1	123	22.7	71.1
Availability, yearly %	85	80	85	80	85	85
Thermal Efficiency %, Net Calorific Value, LHV	41.4	41.8	29.9	32.8	57	33
Decommissioning costs	15	15	15	15	15	300
Emissions/waste disposal costs	Carbon Price	Carbon Price	Pipeline cost Carbon Price	Pipeline cost Carbon Price	Carbon Price	Nuclear Waste €0.91/MWh
Cost uncertainty[b]	1	2	3	3	1	3

a: Costs include capture only, not the costs of CO_2 transport and storage.
b: authors' estimation; 1: low; 2: medium; 3: high
c: Costs for nuclear plant only. Adding a 400MW CCGT plant increases the capital costs of this option by €24.3 million
Costs come from IEA (2010) and NETL (2010).

Coal

Coal plants are attractive due to coal's abundance and relatively low cost. However, burning coal releases relatively large amounts of carbon dioxide. The growing concern about climate change has spurred interest in coal technologies with limited carbon dioxide emissions. The most promising technology currently being developed is carbon capture (CC).

The efficiency and output of coal plants depend on various factors: the specific technology that is used, weather characteristics and the quality of the coal are the main parameters. The average temperature of the water used to cool plants has an impact on efficiency, which is lower when the temperature is higher. This explains why coal plants in Northern Europe tend to achieve efficiency rates that are higher than in the US. Coal that has low energy content and high sulphur content also tends to burn less efficiently.

In this study we consider two coal plant technologies: Pulverised Coal (PC) and Integrated Gasification Combined Cycle coal (IGCC). PC is the most common coal plant technology currently in use. Although the technology is constantly being updated, it is well established and this type of coal plants is built routinely, which decreases the risk of cost overruns. In a PC plant, coal is ground down and combusted in a boiler, producing steam to drive a turbine and generate electricity. There are various options for PC plants. Typically technologies that use higher pressure provide higher efficiency at higher capital cost. These types of plants are used in areas where the cost of coal is relatively higher, i.e. they are more common in Europe and Japan than in the US. The numbers presented in Table 2 refer to a supercritical or ultra supercritical PC plant, the high-efficiency plant type. The overnight cost (the cost that would be incurred if the plant could be built instantaneously) for this type of plant is assumed to be just over €1400/kW in 2008 currency. Costs for all the coal plant options come from NETL (2010). It actually takes about 4 years to build a coal plant and therefore we account for the credit cost during the construction phase as well. The overnight cost of plants with carbon capture includes the cost of the carbon capture components, but not the transport or storage costs, dealt with separately. All the plants are assumed to have scrubbers, to limit emissions of sulphur oxides.

In an IGCC plant coal is converted into synthetic gas (syngas) which is then combusted in a gas turbine to generate electricity. The capital costs for constructing an IGCC are higher, at just under €2450/MW. IGCC plants also have the potential to reduce pollution levels more cheaply than traditional PC plants. After converting the coal into syngas, impurities can be removed prior to combustion, leading to lower emissions of nitrogen oxides (NOx), sulphur oxides (SOx) and mercury. This characteristic also means that it is cheaper to combine carbon capture and storage (CCS) with this type of plant than with PC plants. Up to 90 percent of the CO_2 can be captured through the CCS process. Energy is expended in capturing carbon and this decreases the efficiency of power plants with carbon capture. The efficiency of PC plants decreases by about 11.5 percentage points, whereas the efficiency of IGCC plants decreases by about 9 percentage points.

The figures presented in Table 2 exclude the cost of transport and storage of carbon dioxide which are accounted for separately. These costs vary greatly with the specific characteristics and location of both the power plant and the storage facility. We rely on Irish-specific cost information for transportation and storage from CSA Group (2008). We assume that a new coal plant would be placed at the Moneypoint site, since it is well connected to the grid and has access to a port for incoming coal deliveries. CSA Group (2008) calculated that a pipeline from the Moneypoint site to Kinsale would run for 185km onshore and 50km offshore and would cost around € 230 million in capital costs. In addition the study reports another €37 for injection wells and platforms. The results presented here are based on this pipeline length and injection platform. We assume that the pipeline will last for 50 years.[1] There has been talk of avoiding potential problems from landowners and routing the pipeline off shore instead. If the pipeline were routed all offshore (following the Kerry coastline) the costs would increase both because of the increased length and because offshore pipelines are about €0.2 million/km more expensive (IEA 2008) (based on projects taking place between 2005 and 2007). It might also need an additional booster station due to the longer length.

The site of the CCS plant is unlikely to be dictated by location of available storage, since electricity transmission is more expensive than carbon dioxide pipelines (Newcomer and Apt, 2008).

Nuclear

We also consider the option of a nuclear plant, although we conclude that nuclear power is unlikely to be part of the Irish portfolio in the foreseeable future.

Table 2 shows that the overnight capital cost is high for nuclear plants. Coupled with the greater cost of capital and the long construction period for this option, it leads to the highest capital costs when calculated on a yearly basis. The overnight cost we use here is towards the high end of available estimates.[2] We use this figure for three main reasons. First of all nuclear plants being built currently are going significantly over budget and behind schedule (see Annex 2 in Schneider et al., 2009). Construction underway in Finland on a new European Pressurized Water Reactor (EPR) originally expected to be completed in 2009 at a cost of over €2000 per kW in 2008 money is now not expected to be complete until 2014 and 50 percent over budget by 2009 (for a detailed timeline of the project see Annex 4 in Schneider et al., 2009). This is the first of the new generation of nuclear power stations and may suffer from first-of-a-kind costs with costs falling for subsequent generators. Second, as local know-how increases, building costs tend to fall for the second and subsequent plants (if built within about 18 months of each other). Ireland would only have use for one nuclear plant for the foreseeable future given the limited size of its demand. Finally, Irish citizens

[1] The lifetime of a pipeline is generally assumed to be between 50 and 100 years , but in this case the project life is likely to be determined by the storage capacity of Kinsale, estimated to be somewhat greater than 50 years if it is used to store carbon from a 900MW coal plant (SEI, 2008).

[2] MIT (2008) estimated $4,000 (€2,920) per kW and EIA (2009a) estimated the cost at $3318 (€2,100) per kW. IEA (2010) reports costs for OECD countries varying between $1,556 (€ 1,058) and $5,858 (€ 3,983) per kW.

appear particularly opposed to nuclear generation. A Eurobarometer survey (European Commission 2007) shows that the Irish population is amongst the less keen to adopt nuclear electricity generation. This would plausibly increase costs of construction by increasing the time needed to obtain approval for the project. This also suggests that the likelihood a nuclear plant would be ready to be commissioned in Ireland by 2025 or even 2030 is extremely slim.

Nuclear power stations are designed to run as baseload, reach their minimum efficient capacity at a fairly large 1000MW of capacity, and are not designed to change their output level very easily. With such a large capacity relative to maximum system demand, an unexpected outage would cause a big shortfall of supply. There has to be sufficient extra capacity on the system to be able to back the largest plant. For this reason we have added an additional 500MW CCGT gas plant to make the system as reliable as it is with the other technologies analysed here, based on loss of load expectation calculations.

Natural Gas

Natural gas fuelled CCGT plants are the cheapest to build and maintain. The technology is proven and the construction times are short. This makes it fairly inexpensive to build, as shown by the yearly capital costs displayed in Table 2. The main disadvantage of this option for the Irish system is that a new natural gas-powered plant increases the dependency on natural gas, which is already high. Whereas there is some indigenous natural gas in Ireland, for most of it the island finds itself at the end of the pipeline that comes from Russia. In this study we do not measure security of supply explicitly, but we analyse the percentage of electricity generated by each fuel under the different plant options to define the reliance of the system on each fuel.

Wind

Wind is likely to be a large player on the island of Ireland in 2025. Here we assume that total installed wind capacity is 6000MW by 2025. With this high level of wind, we expect that it will need to be curtailed on occasion, to guarantee reliability of the system. Curtailment of wind in Ireland is recognized to be inevitable given the current technology (see e.g. Clifford and Clancy, 2011).

The All-Island market

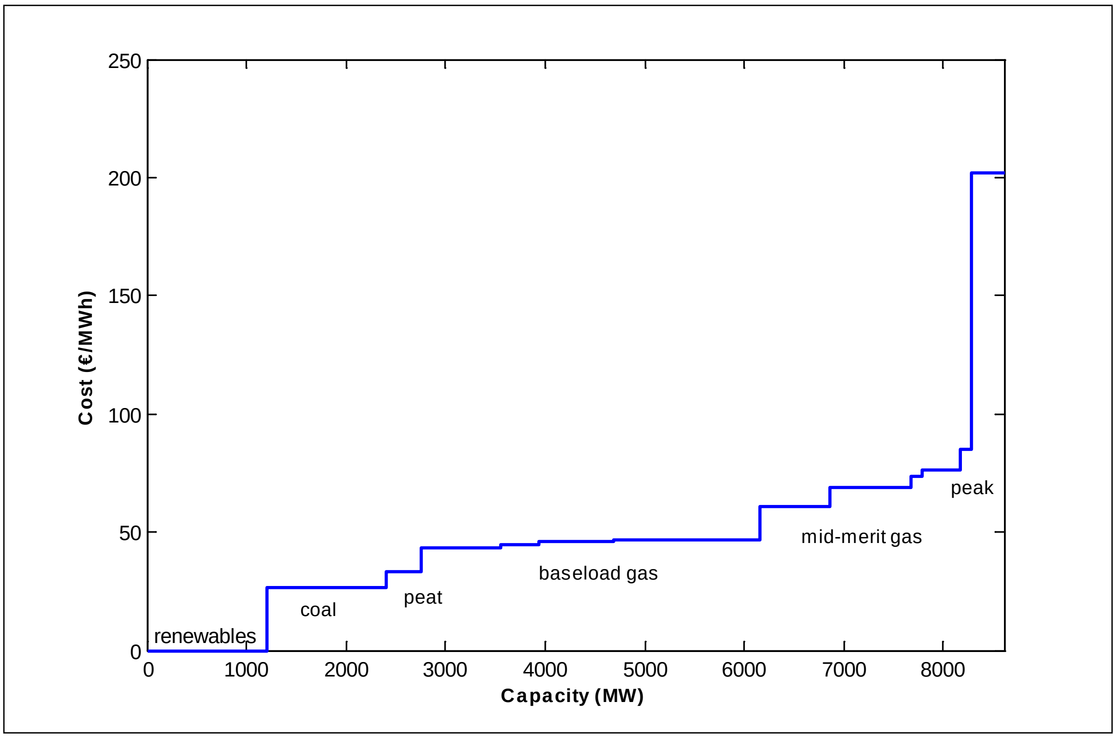
Ireland has a small, relatively isolated, electricity system. It is organised as an All-Island market, set up in November 2007. The wholesale market encompasses both the Republic of Ireland and Northern Ireland and is designed as a mandatory pool with capacity payments. Generators bid the short-run marginal cost of generation into the pool and they are remunerated for their capital costs by a system of capacity payments.

Figure 1 shows the merit dispatch curve for the entire island of Ireland at the end of 2007. The graph shows the installed capacity of each type of electricity generation on the horizontal axis, and the marginal cost of generating electricity with each technology on the vertical axis. The price of each technology changes with fuel and carbon permit prices. Figure 1 is drawn using average 2007 fuel prices and with the carbon dioxide permit price set to zero, in line with its 2007 value. As of the 1st September 2008 there were 920 MegaWatts (MW) of wind on the system. There was also some indigenous peat generation and about 1200MW of coal, but most of the system relied on natural gas, which in 2007 was responsible for about 55 percent of the electricity generated (CER 2008).

During the first year of the All-Island market, the system marginal price has generally followed the trend in fuel prices and has risen when the difference between demand and available capacity was low, as expected (MMU 2009). Flows along the existing interconnector with Scotland have been lower than expected, probably because of issues surrounding interconnector governance and operation (SEM Committee, 2009).

In 2008 wind generation accounted for about 11 percent of generation capacity and for 4 to 7 percent of the electricity generated, depending on the quarter, with the highest share in the winter (MMU 2009).

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



As mentioned earlier, several plants will stop generating in the near future. Table 3 summarises which plants are expected to be decommissioned before 2025 and their size.

Table 3. Decommissioned capacity between 2009 and 2025

Station Name	Capacity (MW)
Great Island	216
Tarbert	590
Ballylumford Units 4, 5 and 6	510
Northwall Units 4 and 5	267
Kilroot	534
Moneypoint	844.5
Total	2961.5

In order to replace the closing plants and to meet growing electricity demand, new plants have to be built. Table 4 shows the expected commissioning date of new plants on the system, their size and the type of fuel used, in line with estimates reported in the EirGrid Generation Capacity Statement (2010). In order to make sure that the 2025 demand level is met, we also add four further plants to the system, including the expected replacement of Moneypoint. These are reported under 'additional plants'.

Table 4. Additional capacity in 2025

YEAR	Station Name	Capacity (MW)	Fuel type
2011	Meath Waste-to Energy	17	Waste
2012	Cuilleen OCGT	98	Natural Gas
	Dublin Waste-to-energy	72	Waste
	Nore Power OCGT	98	Natural Gas
2014	Cahir OCGT	98	Natural Gas
	Caulstown OCGT	55	Natural Gas
	Additional plants		
	Kilroot CCGT	400	Natural Gas
	Endesa CCGT	420	Natural Gas
	Co.Louth CCGT	400	Natural Gas
	Moneypoint replacement	1000	various

There will also be further deployment of wind generation and increased interconnection to Great Britain. We assume there is 6000MW of wind on the All Island system by 2025. Wind generation is assumed to be available 31 percent of the time on average. This wind deployment is consistent with the amount needed to meet the Irish government's target of generating 20 percent of total electricity with renewable energy (DCMNR 2007), as stated in EirGrid (2010).

The Irish electricity network is currently connected to Great Britain through the 500MW Moyle interconnector (that runs at 400MW) between Scotland and Northern Ireland. Eirgrid is also building an East-West interconnector running from North County Dublin in Ireland to Barkby Beach, North Wales in Britain. This is expected to be complete by the end of 2012 and will bring total interconnection capacity to 900MW. In this study we measure total electricity generation costs under three levels of interconnection for 2025: 900MW, 1400MW and 1900MW.

To model the interconnector we need to define the price of electricity at the British node. The GB portfolio used in this study follows the National Electricity Transmission System (NETS) Seven Year Statement (2011) up to 2019. Table 5 summarises the plants on the British market by type of fuel. As can be noted, the assumption is that there will be a sizable increase in wind generation capacity in Great Britain as well. After 2019 we assume that both demand and the generating plant portfolio do not change.

Table 5. Capacity in Great Britain, by type of fuel, 2025

Type of fuel	Share of Capacity
Coal	19%
Gas	43%
Nuclear	11%
Renewables	26%
of which wind	23%
Total installed Capacity (GW)	111

Fuel and carbon prices

The price of oil is notoriously volatile. The price of Brent crude oil went from a high of about \$140/barrel in July 2008 to a low of about \$30/barrel in December 2008. It has since bounced back and in January 2012 is hovering around \$110/barrel. Carbon dioxide permit prices have also varied significantly over the year. In order to account for this volatility, we evaluate how the electricity generation portfolios perform under a variety of price levels. These prices are reported in Table 6 in terms of €/MWh. The high price corresponds to an oil price of \$168/barrel, the medium price is \$115/barrel and the low price is \$68/barrel, all in 2008 currency.

The prices of natural gas and diesel oil are assumed to track oil prices. We assume that coal, peat and uranium (used in nuclear power plants) have a constant price in real terms across the three fuel price scenarios. While the assumption of a constant price for coal is not fully realistic, we adopt it for two reasons. First of all the price of coal does not vary in line with oil prices (Zaklan *et al.*, 2012). Second, in this study we are interested in scenarios with different natural gas to coal prices, since this drives how coal and natural gas fuelled plants compare in the merit order.

Table 6. 2025 Fuel Price Scenarios in €/MWh, 2008 currency

	Coal	Oil	DO	Gas	Peat	Nuclear
Low	11.2	25.1	46.0	19.4	12.0	5.85
Medium	11.2	46.1	84.7	35.6	12.0	5.85
High	11.2	67.2	123.3	51.9	12.0	5.85

Which of the prices is more realistic is unclear. While we have experienced periods with high oil and natural gas prices, in recent years there has been a move towards a shale-gas 'revolution'. Shale gas is found abundantly, especially in the United States, and current technology allows its extraction at competitive costs. If large amounts of shale gas continue coming to the market, we expect that future natural gas prices will be lower than the scenario where shale gas extraction is limited (e.g. see Jacoby et al., 2012). The latter could happen if the amount of recoverable shale gas turns out to be small or if strong environmental regulations are eventually imposed.

We also determine how the system performs at three levels of carbon dioxide permit prices, from a low price of €16/tonne of CO_2, to €32/tonne CO_2 and a high price of €64/tonne of CO_2, all in 2008 currency.

Model and results

The simulations rely on an optimal dispatch model for the all-island wholesale electricity market, modelled as a mandatory pool market 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. In line with the bidding principles of the SEM, generators bid their short run marginal cost, which includes the cost of fuel and carbon dioxide emissions. Plants are stacked according to their bid, from the cheapest to the most expensive, and the cheapest plants that are needed to meet demand in each half hour are dispatched. The most expensive plant that is dispatched determines the shadow price (SP) paid to all plants that are generating during that period.

The model assumes that there are no transmission constraints, no costs to increasing and decreasing the level of production and no minimum down times. In reality, it takes several hours for a thermal plant to warm up to the point where it can generate electricity. To take this feature into account, we assume that a certain number of thermal plants must always be on at their minimum stable capacity. The number of plants that are constrained on depends on the time of the year and the level of electricity demand and is determined on a monthly basis by the model. When thermal plants are constrained on and would not otherwise have been dispatched by the market, they do not bid their marginal cost into the market; rather, they are compensated for this generation through constraint payments which equal their marginal cost, regardless of market prices. At times the need to constrain on thermal plants might also cause the curtailment of available wind generation.

To analyse the effects of interconnection, a similar model is set up for Great Britain. We assume that there will be flow along the interconnector every time the price in one jurisdiction differs by more than a transaction cost of €3/MWh. 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. 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, which is governed by BETTA (British Electricity Trading and Transmission Arrangements) and is based on voluntary bilateral arrangements between generators, suppliers, traders and customers.[3] The current system, however, does not appear to provide sufficient incentives for future investment, so it is likely to undergo reforms. One of the options under consideration is a move towards a system that includes capacity payments (DECC, 2011). The final market rules in Great Britain will of course influence the flows along the interconnector.

The results of this model allow us to compare the total cost of the electricity system under a variety of scenarios and in addition analyse both the cost of the whole system and also the cost to consumers.

For each scenario we measure the short run and capital costs to generators and the costs to consumers (based on the wholesale costs of electricity). We abstract from the costs of distribution and retail 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 2007 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.[4]

We define the yearly cost (YC) of the electricity system in two alternative ways. Equation 1a shows total yearly costs as the ones incurred by consumers (CC), net of producer profits (PP) and interconnector profits (IP). This assumes that the interconnector gains ultimately accrue to the system itself, because interconnection is controlled by State-owned agencies or firms that are resident in the jurisdiction. Equation 1b represents total yearly costs without taking into account interconnector profits. This view of total costs is appropriate if most of the profits from the interconnector accrue to agents residing outside of the jurisdiction. Reality is likely to be somewhere in between these two options.

[3] For more on BETTA and its performance, see Newbery (2006).
[4] Final industrial and residential costs for the Republic of Ireland come from IEA (2009b). The estimate of the cost of electricity in the SEM (including the system marginal price, the cost of capacity payments and other ancillary costs) is reported in MMU (2009).

YC = CC – PP – IP (1a)
YC = CC – PP (1b)

Total yearly producer profits are calculated as follows:

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

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*.

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 and capacity payments, and pays annualised capital costs:

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

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:

$$CC = \sum_h d_h P_h + CAP + T \tag{4}$$

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.

Total yearly system cost therefore can be simplified to the following alternative equations.

$$YC = T + \sum_i \left(OM^i + K^i + \sum_h FC_h^i\right) - \sum_h (| P_h^{AI} - P_h^{GB} | \cdot fl_h) \tag{5a}$$

$$YC = T + \sum_i \left(OM^i + K^i + \sum_h FC_h^i\right) \tag{5b}$$

The difference between the two versions of equation 5 is that in 5a we include interconnector profits when calculating total system cost, and in 5b we do not.

There are various elements to study. First of all we analyse the expected total costs for 2025. Then we explain the differences between technologies by looking at the changes in emissions, imports and exports, level of wind curtailment and percentage of electricity generated by fuel.

We analyse the case of average interconnection (1400MW) and average fuel and carbon prices in detail. We report tables for all combinations of carbon and fuel price in the appendix for this option.[5]

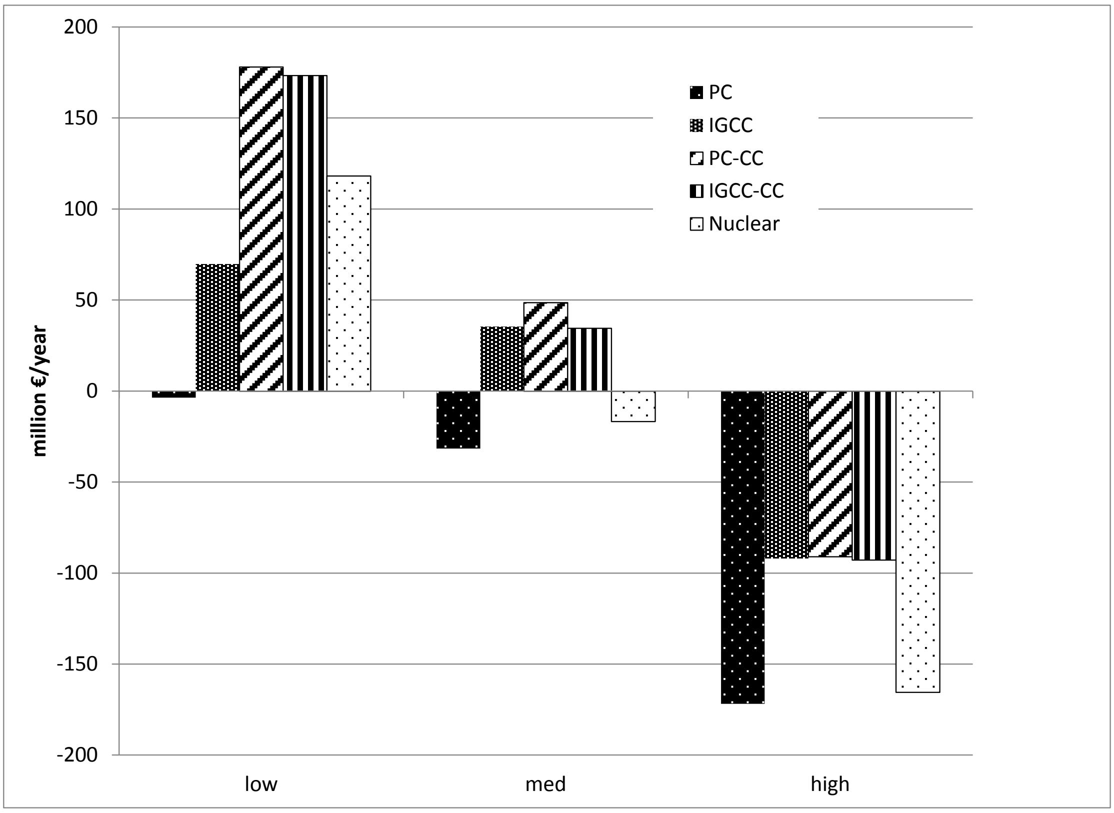
System costs

In Figures 2 and 3, the costs to the system is reported as the difference between total costs when the different technologies are adopted and total costs when natural gas fuels the replacement plants. Note that the nuclear option includes the capital costs associated with the additional 500MW CCGT plant needed for system reliability. We are implicitly assuming that all additional costs that we do not explicitly measure (specifically transmission and distribution costs) are the same across all options. Any positive values therefore show that total costs are higher for that specific technological option, and negative values indicate that total costs are lower. Figures 2 and 3 report the total yearly system costs with interconnector gains (eq. 5a) and without interconnector gains (eq. 5b) respectively, when the interconnector is 1400 MW and the price of carbon permits is €32/ton. As mentioned earlier, it is likely that some of the interconnector profits should be considered when calculating total system costs and benefits. We do not attempt to estimate the correct share of interconnector profits to include, but present the results for both scenarios.

Not surprisingly, the option with natural gas plants is cheap when natural gas prices are low with respect to coal prices (and to some extent when fuel prices are at their medium level). Note that the pulverised coal option with no carbon capture leads to slightly cheaper system costs for low natural gas prices. This somewhat counterintuitive result is due to the PC plant in this case not running at full load and therefore leading to higher imports. This can be verified by observing how the results change when we exclude interconnector profits from the calculation, as shown in Figure 3. In this case the natural gas option leads to the lowest system costs when natural gas prices are low.

[5] Results for the options with 900MW and 1900MW of interconnection are not presented here, but are available from the authors.

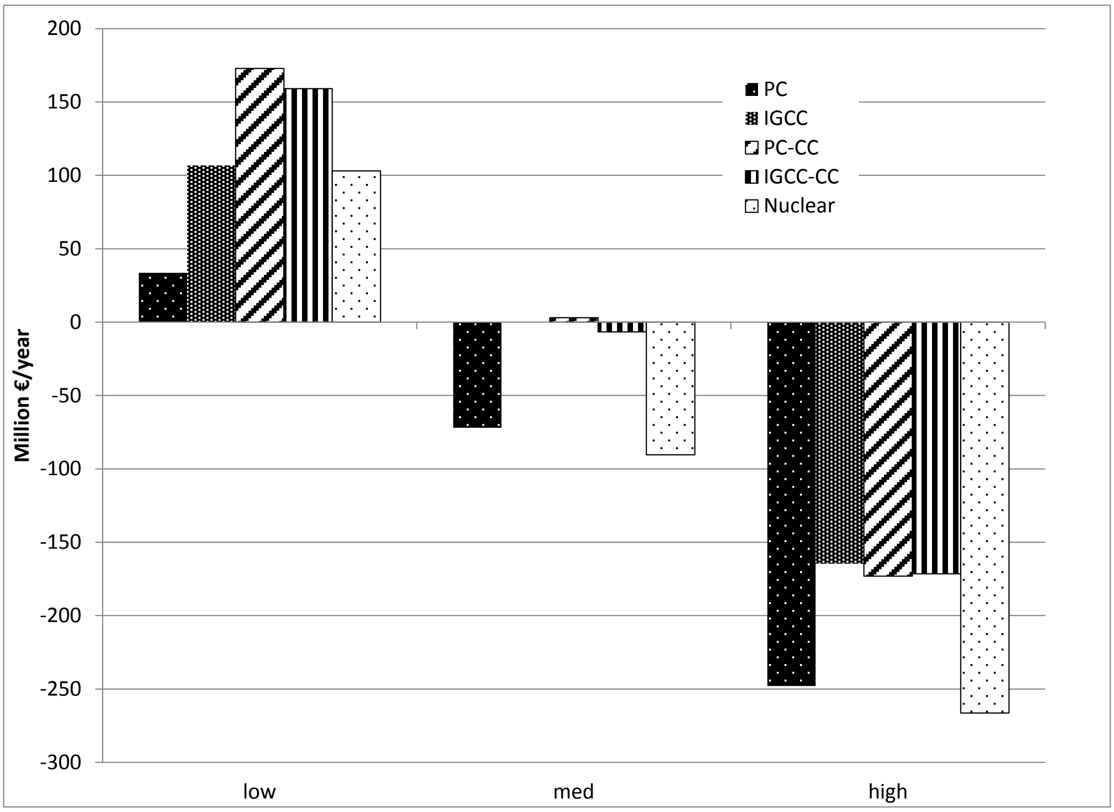
Figure 2. Difference in total yearly system costs from CCGT option, with interconnector gains



Interconnector = 1400MW; Carbon price = €32/ton

It is a bit more difficult to put these numbers in perspective. For example, Figure 2 shows that for medium fuel prices, the option with a PC plant produces total system costs that are €32 million per year less that those with the CCGT option. We cannot describe the change in costs in terms of percentage of total system costs because we do not calculate the total costs of the system. Doing so would involve measuring the capital costs of all existing plants in the year 2025, together with the costs of the transmission and distribution infrastructure. For an idea of the order of magnitude of the costs, consider that total fuel costs are around €1 to €2 billion per year, depending on the fuel and carbon dioxide permit costs.

Figure 3. Difference in total yearly system costs from CCGT option, without interconnector gains

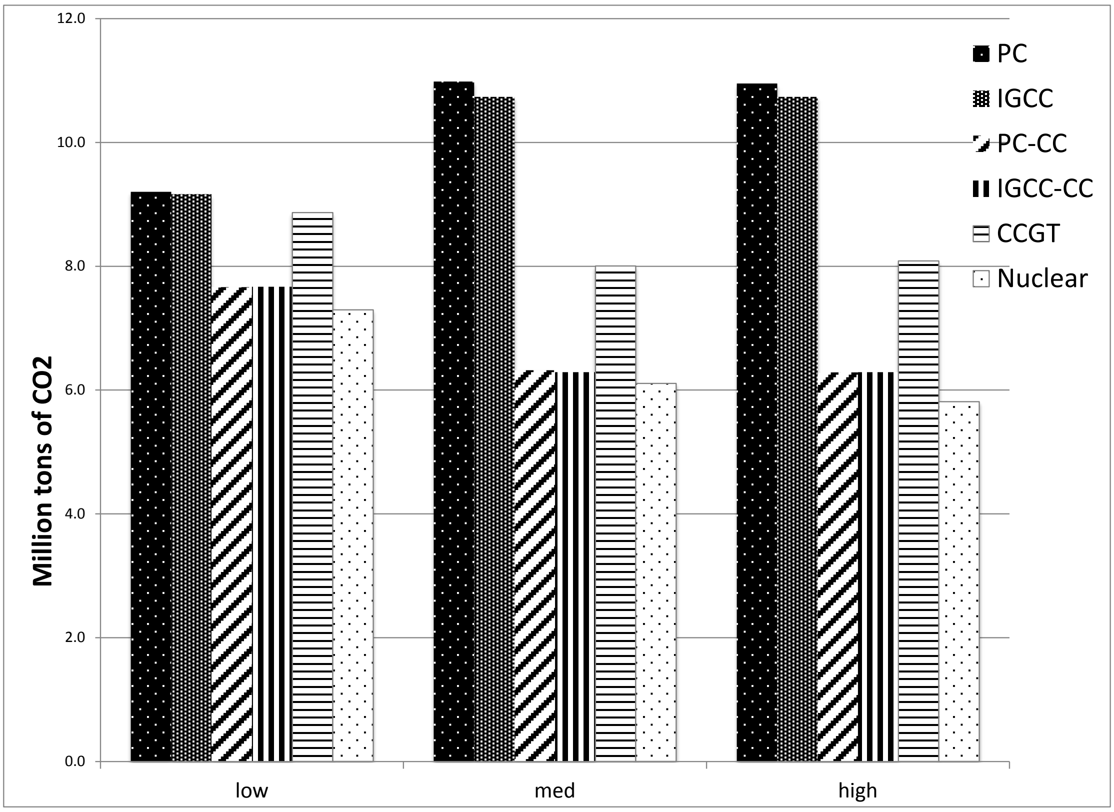


Interconnector = 1400MW; Carbon price = €32/ton

Emissions

Figure 4 shows how emissions vary with the different technology options. When the fuel price of natural gas is low, gas generation becomes more competitive than coal generation, especially since there is a cost to carbon dioxide emissions. This means that for low fuel prices coal plants without carbon capture are not running at full capacity. This explains why emissions in the scenarios with coal plants without carbon capture are just slightly larger than emissions in the scenario with CCGT in the low fuel case. As soon as coal becomes more competitive (i.e. when the cost of natural gas is higher), scenarios that have coal plants without the carbon capture option produce 35 to 40 percent more emissions than the CCGT scenario. Scenarios with carbon capture produce about 15 percent fewer emissions than the CCGT case.

Figure 4. Million tons of CO2 emissions for All Ireland system, 2025, for 3 fuel prices scenarios



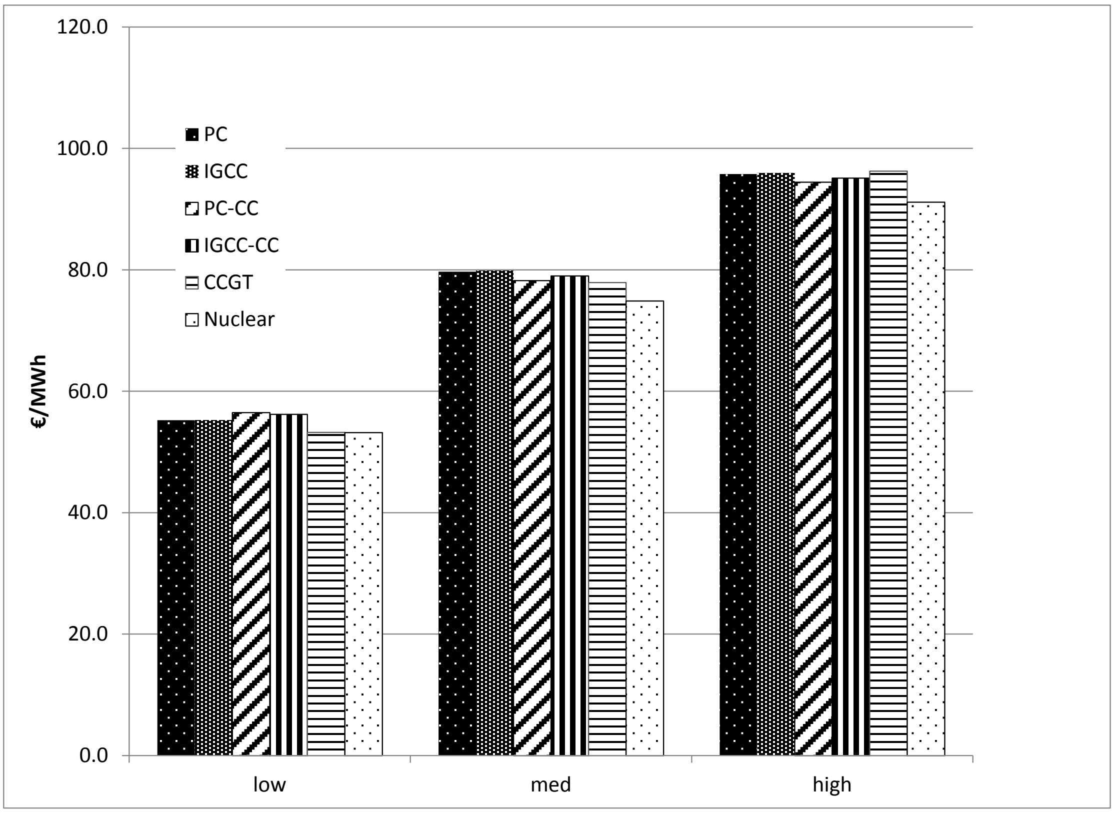
Interconnector = 1400MW; Carbon price = €32/ton

Shadow price and capacity payments

The shadow price, which measures the average short run fuel and carbon dioxide costs, is not greatly affected by the changes in technologies. The explanation is quite simple: we are looking at different baseload technologies and these tend not to set the marginal price very often. In the All-Ireland system, the marginal price is typically set by an older natural gas powered plant. For the same reason, the shadow price is strongly correlated to the price of natural gas and increases significantly when the fuel price increases. Figure 5 shows how the sum of capacity payments, fuel and carbon costs varies with changes in baseload technology and fuel prices. The option with nuclear power is associated with the lowest price in these simulations, but not by much. The difference between the cheapest and the most expensive technology is of the order of 5 percent.

Note that we do not calculate the cost of uplift here, which is designed to recover costs that generators incur when turning their plants on and are not covered by the revenue received in the bidding process (MMU, 2009). This also means that if plants turn on and off more frequently, the uplift will tend to increase. We do not expect the uplift to vary across the technological options we present, since the plants we consider here are baseload plants and are therefore not going to turn on and off very frequently. The situation may change as the plants age and newer and more efficient plants come on the system. In that case, plants that display higher turning on and cycling costs may in fact cause the wholesale price to increase more than plants that have lower turning on and cycling costs.

Figure 5. System Shadow Price + Capacity Payments, €/MWh, year 2025; 3 fuel price scenarios



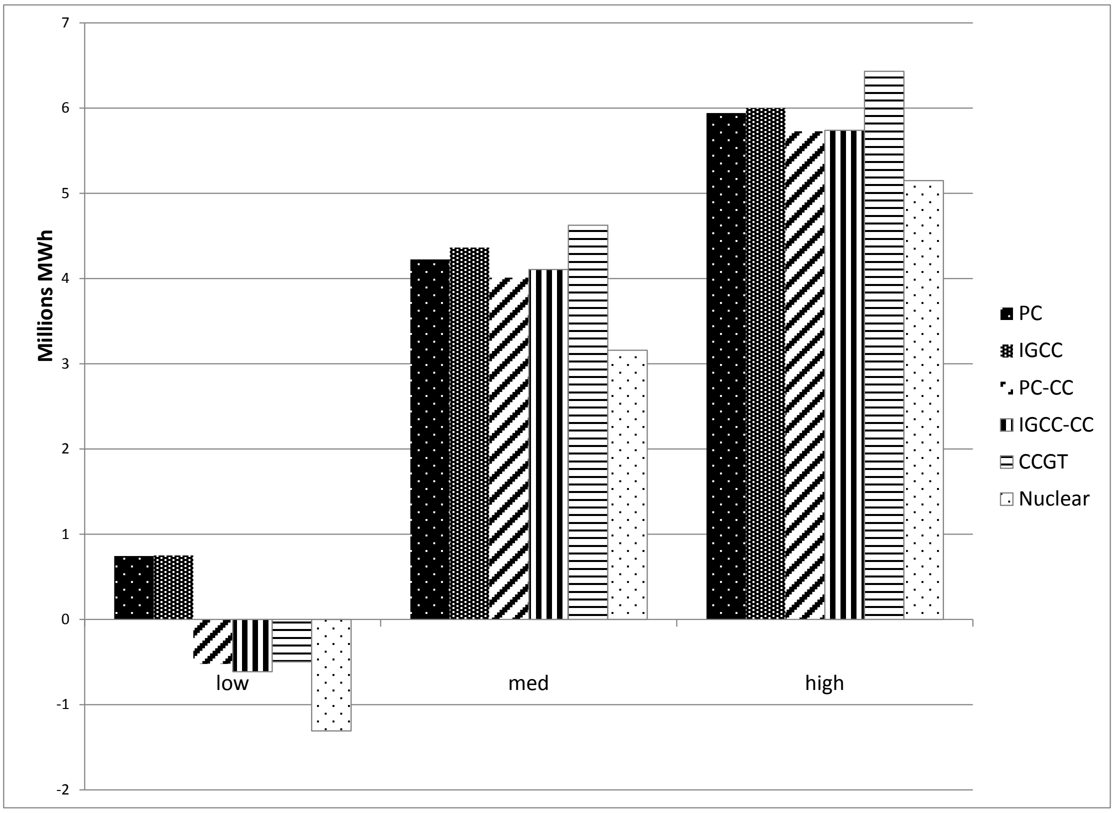
Interconnector = 1400MW; Carbon price = €32/ton

Imports and Exports

The different technology options have some impact on the amounts of imports and exports between the island of Ireland and Great Britain. When a nuclear power plant is in place, there are consistently lower net imports (imports – exports) across all fuel price scenarios. The Irish system relies on natural gas generation relatively more than the British system. Therefore, when the price of natural gas is relatively low with respect to the price of coal, imports from Britain are lower and exports to Britain are higher. As soon as natural gas generation becomes more expensive than coal generation, which in this case happens when the medium level of natural gas price is reached, net imports from Great Britain significantly increase, since power in Great Britain is not affected as much by the cost of natural gas.

Figure 6 displays net imports into the island of Ireland. Exports are represented as columns below zero.

Figure 6. Net imports, million MWh, 2025; 3 fuel price scenarios



Interconnector = 1400MW; Carbon Price = €32/ton

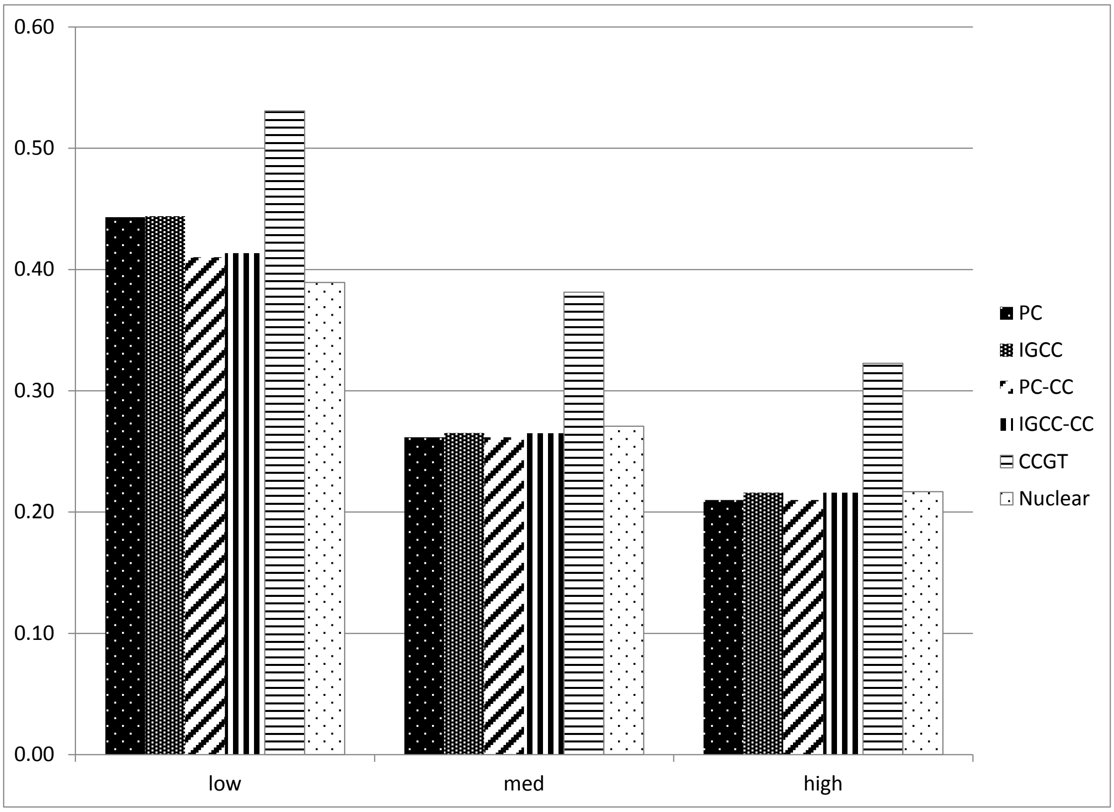
Security of supply

As mentioned earlier, natural gas generation supplies more than half of total electricity demand in Ireland. Ireland imports 90 percent of its natural gas from Great Britain through two interconnectors that link the Irish system to Scotland and the British national grid system. Ireland is also characterised by low levels of natural gas storage, which is currently limited to one operation in Kinsale. The combination of these factors suggests that high reliance on natural gas might cause concerns related to security of supply. In this analysis we do not explicitly measure the cost to the system of security of supply concerns. We therefore supplement the analysis with a discussion of how the different technologies might affect security of supply.

Figure 7 shows the share of natural gas as a proportion of total electricity demand. When fuel prices are low, electricity in Ireland tends to be relatively cheaper than in Great Britain and therefore net imports are lower. This also means that most of the island's demand is met by generation on the island of Ireland, which explains why the share of natural gas generation is higher. When the price of natural gas increases, net imports along the interconnector are larger and the share of total demand met by natural gas generation decreases.

Security of supply might also be analysed through a different perspective: the amount of fuel storage available on the island. Natural gas storage levels are notoriously low on the island of Ireland (CER and NIAUR, 2009).

Figure 7. Proportion of electricity demand generated by natural gas, 2025



Interconnector = 1400MW; Carbon price = €32/ton

4. Conclusion and future research

This paper analyses how replacing the Moneypoint power plant will affect the electricity system on the island of Ireland by providing a snapshot analysis of the system in 2025, the year we assume the replacement plant will be commissioned. The technologies considered as replacement are coal plants with and without carbon capture, natural gas fired plants and nuclear plants (although we argue that a nuclear plant is not a realistic option for Ireland at the moment). To capture the uncertainty of energy markets, we study the issue for a variety of fuel and carbon dioxide permit prices.

We find that no technology is always the cheapest, across all ranges of fuel and carbon prices. Not surprisingly, the natural gas–fired option is cheap when natural gas prices are low, but expensive when natural gas prices are high.

The short-run price (including capacity payment, but not uplift costs), does not vary significantly across the technological options since the system marginal price is set by plants other than the new baseload plants. This result might change over the course of the plant's lifetime, as newer and more efficient plants are added to the island's plant portfolio potentially pushing the baseload plants considered here to operate in a more flexible way. To capture the changes in the operation of plants over time, it would be interesting to extend this analysis from a snapshot study to a lifetime study. This would involve some necessarily strong assumptions on how the rest of the plant portfolio evolves.

There are larger differences between the technologies when we consider the amount of total emissions for the system. Emissions vary by as much as 35 to 40 percent for the case with 1400MW of interconnection. Not surprisingly, the options with coal plants that are not fitted with carbon capture are associated with the highest levels of carbon dioxide emissions for the system as a whole.

Some of the technologies we consider in this study have highly uncertain costs. The lack of commercially-developed CCS plants around the world means that over time, as the technology matures, uncertainty around its costs will decrease. Moreover, while future natural gas prices will always be volatile, the expansion (or not) of shale gas will strongly influence the cost of natural gas. Cheaper future natural gas price would obviously make the natural gas powered option more attractive. Given that the uncertainty in costs of both coal with CCS and natural gas are likely to be greatly reduced in a few years, it would be interesting to study the cost of delaying the Moneypoint replacement decision. This could be done by comparing the extra costs associated with maintaining an older plant for a few more years to the advantage coming from more precise information on the cost of alternative technologies.

Finally, we study how the different options are going to impact energy security, and specifically Ireland's reliance on natural gas. Not surprisingly, the option of substituting the current Moneypoint plant with natural-gas fired generation is the one that causes the highest dependency on natural gas, independent of variations in natural gas and carbon prices. For this option, more than 50 percent of total demand is met by natural gas fuelled electricity. The dependency on natural gas is comparable to the one in 2010, despite the large increase in the installed capacity of wind.

As mentioned earlier, this study does not analyse investors' incentives to build new power plants. However, this is a relevant issue in the current deregulated market. If new investment is deemed non-economical, either because of the risks associated with global uncertainty or because the market does not compensate for needed plant flexibility, reliability of the system might be compromised.

Another area of future research involves considering different market organisations for Great Britain. The current system does not appear to provide sufficient incentives for future investment and a system of capacity payments is being considered. The results on emissions and costs in this study are affected by the extent of imports and exports between the island of Ireland and Great Britain. The precise nature of the British electricity market in 2025 will influence the British electricity prices and therefore the level of imports and exports with neighbouring electricity systems. An analysis that evaluates different outcomes for the British market would therefore appear useful.

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Appendix A – Complete tables for 1400MW interconnection

Table A.1 Difference in total yearly system costs from CCGT option, with interconnector gains, million euro/year

	Fuel Scenario	PC	IGCC	PC-CC	IGCC-CC	Nuclear
Carbon price €16	low	23	94	190	176	149
	med	-68	6	84	63	15
	high	-211	-130	-58	-73	-116
Carbon price €32	low	-4	70	178	173	118
	med	-32	36	49	35	-17
	high	-172	-92	-91	-93	-165
Carbon price €64	low	-45	30	158	161	35
	med	11	124	14	-3	-71
	high	-63	5	-138	-150	-237

Table A.2 Difference in total yearly system costs from CCGT option, without interconnector gains; million euro/year for 3 natural gas price scenarios

	Fuel Scenario	PC	IGCC	PC-CC	IGCC-CC	Nuclear
Carbon price €16	low	33	105	186	174	120
	med	-118	-39	35	20	-52
	high	-287	-201	-134	-142	-219
Carbon price €32	low	34	107	173	159	103
	med	-72	0	3	-7	-90
	high	-248	-165	-173	-171	-266
Carbon price €64	low	38	112	145	140	49
	med	4	84	-36	-46	-144
	high	-160	-84	-229	-231	-349

Table A.3 Yearly emissions, in thousand tons of CO_2, 2025

	Fuel scenario	PC	IGCC	PC-CC	IGCC-CC	CCGT	Nuclear
Carbon price €16	low	9,782.6	9,654.0	7,458.5	7,349.3	8,576.5	6,976.6
	med	11,104.0	10,841.9	6,645.6	6,421.0	8,151.5	5,918.6
	high	11,074.6	10,812.9	6,616.2	6,392.0	8,122.1	5,898.7
Carbon price €32	low	9,201.2	9,162.4	7661.6	7,665.9	8,865.5	7,293.1
	med	10,979.6	10,732.1	6320.7	6,287.9	8,004.1	6,106.4
	high	10,948.4	10,733.8	6283.3	6,289.6	8,085.9	5,811.9
Carbon price €64	low	8,391.8	8,391.8	7,767.8	7,538.5	8,991.6	7,438.7
	med	9,635.0	10,071.8	5,939.1	5,928.3	7,352.2	6,080.6
	high	10,315.3	10,051.4	5,552.2	5,541.3	7,162.0	5,362.3

Table A.4 Shadow price + capacity payments, €/MWh, for 3 fuel natural gas price scenarios

	Fuel Scenario	PC	IGCC	PC-CC	IGCC-CC	CCGT	Nuclear
Carbon price €16	low	50.6	50.7	51.0	50.8	48.2	49.2
	med	71.3	71.4	70.9	70.9	70.9	68.4
	high	87.2	87.5	86.8	87.0	89.5	84.1
Carbon price €32	low	55.3	55.3	56.5	56.2	53.2	53.2
	med	79.7	79.9	78.2	79.0	77.9	74.9
	high	95.8	96.0	94.5	95.1	96.3	91.1
Carbon price €64	low	63.3	63.3	64.4	66.1	61.7	61.5
	med	91.4	90.9	90.1	89.7	88.0	83.4
	high	112.8	113.0	110.3	110.3	110.4	104.4

Table A.5 Net imports, GWh, 2025

	Fuel Scenario	PC	IGCC	PC-CC	IGCC-CC	CCGT	Nuclear
Carbon price €16	low	903.1	954.8	413.7	524.9	299.0	-531.1
	med	5763.7	5878.4	5650.0	5875.6	6321.8	5033.0
	high	5841.5	5955.0	5727.9	5952.2	6399.6	5085.4
Carbon price €32	low	745.6	752.3	-521.2	-613.0	-495.5	-1306.4
	med	4225.5	4365.2	4011.5	4106.1	4626.1	3159.6
	high	5943.7	6000.6	5730.0	5740.4	6432.2	5151.5
Carbon price €64	low	890.6	890.6	-1156.6	-1294.4	-794.0	-1680.5
	med	3583.6	3127.7	2597.8	2701.3	3437.3	1823.4
	high	5956.2	6079.4	5719.8	5840.9	6668.8	5208.7

Table A.6 Natural gas generation, as a share of demand (%)

	Fuel scenario	PC	IGCC	PC-CC	IGCC-CC	CCGT	Nuclear
Carbon price €16	low	41	41	40	40	51	37
	med	21	22	21	22	32	22
	high	21	22	21	22	32	22
Carbon price €32	low	44	44	41	41	53	39
	med	26	27	26	26	38	27
	high	21	22	21	22	32	22
Carbon price €64	low	49	49	42	40	54	27
	med	33	33	32	32	44	32
	high	23	23	23	23	34	23

Year	Number	Title/Author(s) ESRI Authors/Co-authors *Italicised*
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