PÖYRY

IMPLICATIONS OF INTERMITTENCY

A multi-client study

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IMPLICATIONS OF INTERMITTENCY

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Front cover shows a wind farm at Black Hill, UK (Image courtesy of RES)

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EXECUTIVE SUMMARY

Introduction

Electricity markets are expected to undergo a radical transition to renewable and other low carbon forms of generation within the next twenty years, with the EU's proposed 2020 renewable targets setting a milestone on the path to a substantially decarbonised electricity sector. If achieved, this transition has the potential to revolutionise established business processes across all timescales from infrastructure planning, investment, price formation and the real-time dispatch of generation to meet demand.

Our view is that if the renewables and decarbonisation challenges are to be met, the consequent level of uncertainty over market outcomes is greater than at any time since liberalisation of the electricity industry began. Given this background, the overall objective of this project is to answer the question:

> *'How could the impact of intermittent generation, required to meet targets for renewables and decarbonisation of generation, affect the wholesale energy markets in GB and Ireland?'*

Existing electricity markets

Electricity markets currently operate according to 'predict-and-provide' principles in the short term, with generation investment based on forward market price and revenue expectations in the longer term. Demand is generally treated as uncontrollable, and conventional generation (through a combination of within-day variation in market prices and ultimately system operator dispatch and ancillary services) is actively managed to meet demand with second-by-second resolution.

Impact of renewable and decarbonisation targets

There is a consensus across Europe and world-wide that climate change is an urgent problem and that the electricity sector is a key part of reducing carbon emissions. Milestones have been set for the period to 2020 but the continued drive for decarbonisation of the economy will lead to pressure for further renewable and other low carbon generation beyond that time. Addressing this challenge will introduce a large quantity of generation with technologies which, in large quantities, have the potential to disturb both short-term operation and pricing and longer-term investment decisions in ways which hitherto have not been well understood.

The EU's proposed renewable targets for 2020 imply very significant deployment of renewable generation in the next 11 years, with a target of 15% of final energy use sourced from renewables for the UK and 16% for the Republic of Ireland. This could mean that over 30% of electricity generation will have to be met by renewable energy in the UK, and perhaps 40% in Ireland.

To meet such challenging targets, it is possible that up to 35GW of wind will be required on the GB system by 2020 (33% of total installed capacity) and 6GW in Ireland (43% of total capacity).

Wind generation (and other renewable and low carbon generation technologies to varying degrees) have a number of attributes which mean that significant levels of capacity may perturb the operation of electricity markets:

- wind generation has very low or negative short term operating cost and is therefore commercially inflexible, so the conventional plant will have to follow the residual load;
- as the output of wind generation is intermittent, conventional generation has to be available and scheduled at times when there is little wind generation, and dispatched off when there is a lot of wind leaving a significant capacity overhang; and
- wind generation is unpredictable until close to real time, causing the need for additional system reserve to be held.

Within Europe, these issues are most critical for places such as the GB and Irish markets which are lightly interconnected, with little hydro capacity (a natural balance to wind generation) and which enjoy significant wind resource.

It is not just the renewables targets that are changing the shape of the electricity market. Moving the system to a low carbon base means that nuclear, biomass and CCS coal generation may also be built in large quantities. Based on our current understanding, their preferred mode of operation will be baseload, with much lower flexibility than current thermal plant.

Together these factors have the potential to radically alter the existing wholesale electricity market across all timescales. A system with very large amounts of intermittent generation requires lots of flexible price-sensitive generation to provide backup. However, much of the generation that is likely to be built will be nuclear, CCS and biomass, all of which are designed (and financed) to function at baseload (continuous) operation, and are expected to provide only limited flexibility for commercial as well as technical reasons. In tandem, the load factors and investment economics for more flexible conventional generation are expected to be adversely affected by the wind and other low-carbon generation which is likely to make load following and provision of reserve a more significant cost component of electricity market and system operation.

Basis for the study

To examine these profound shifts that may occur in the electricity market, the overall objective of the work was to:

- develop much more realistic outputs for the portfolio of wind farms in GB and the island of Ireland;
- evaluate the likely thermal plant operating regimes;
- understand the impact on market prices;
- examine the investment outlook for new plant; and
- assess how robust market rules are to these changes.

This report examines in detail the economic and dynamic challenges in introducing large amounts of wind by 2030 in both GB and the Irish markets. It draws on real data from operating onshore and offshore wind farms and is the product of a major modelling exercise to examine market fundamentals.

The backbone to answering the main question is a sophisticated computer modelling tool (‘Zephyr’), backed by a wealth of historical data on hourly wind, demand and generator availability, which has allowed simulation of different scenarios of the GB and Irish market.

The Zephyr model has been designed specifically to allow detailed examination of the electricity markets, as it examines hourly electricity prices (365 x 24 hours per year) for a series of 8 'mini-Monte Carlo' simulations which simulate differing patterns of demand, wind and plant availability. Thus to examine a single year, a total of 70,080 hourly prices are generated, which captures a large part of the variation that could be expected.

To ensure a consistent set of input data for wind generation, Pöyry has used hourly observations from 36 sites across the UK and ROI for the period 2000 - 2007. Pöyry has worked with the UK Met Office to ensure that these sites offer an accurate representation of future wind generation in the UK. For offshore sites, the Met Office provided 'reanalysis' data derived from a wave model, which has allowed consistent wind data to be obtained for offshore sites such as Dogger Bank, the Wash and the Irish Sea. In total, Pöyry has used 2.4 million hourly wind speed records to generate a comprehensive view of future wind generation in the UK and ROI. This allows simulation of any possible future deployment of wind turbines across the UK and Ireland, whether they are offshore, onshore, in Scotland or further south.

This work builds on previous studies, including research from UK ERC, and studies commissioned by BERR (now DECC) for the Renewable Energy Strategy Consultation.

We are grateful for the support of many stakeholders in the energy industries, including the two system operators, several major utilities and government bodies who have provided significant support in terms of data, interpretation and modelling methodology; in particular for wind output and reserve and response requirements. This collaborative approach has delivered a degree of credibility which we believe is unparalleled.

The results of the study represent the views of Pöyry and are not necessarily representative of the views of individual Members or Founders of this study.

Scenarios

The study has explored one 'Core' scenario in detail, and a further nine cases to examine a range of possible outcomes and areas of interest. The Core scenario does not represent a Central or a definitive Base Case for the future. Instead it represents a reasonable starting case to explore the world in which current British and Irish government policy with respect to renewables and CO_2 emissions over the timeframe 2009-2030 is implemented in full. For the Core scenario we have created an alternative 'System Operator Dispatch' case in which we have applied additional constraints on system dispatch, including reserve and frequency response constraints and separately north-south transmission constraints within both GB and SEM.

The Core scenario is a world where there is a drive towards renewables and lower carbon forms of generation. Energy efficiency measures have some impact, leading to electricity demand growing at a relatively low rate – less than 0.5% per year in GB and under 1% in the SEM, despite some further electrification of transport and heating. The price of oil is $70/bbl, with carbon prices at €37/tCO_2.

In GB, the Core scenario assumes that wind capacity rises to 33GW in 2020 and 43GW in 2030, with a GW of tidal. Additionally, there is 1.6GW of new nuclear built by 2020, rising to 9.6GW by 2030. This is counteracted by closures of existing nuclear plant, so that by 2030, 10.7GW of nuclear is on the system. 3.2GW of coal CCS is assumed to be built by 2030 in total. Furthermore, we assume a strong growth in biomass fired plant, with a total of 4.4GW being installed by 2030.

In the SEM, there is a similarly fast growth in installed wind capacity, from 1.2GW in 2010 to 6.1GW by 2020 and 7.9GW by 2030. In this scenario, wind rises to a higher penetration of the SEM than the GB market. There is a small growth in CCGT capacity

Peaking generation does not grow significantly, although the amount of peaking generation is much greater in the SEM than in GB.

With the very significant volumes of renewable generation in the Core scenario, it is unsurprising that carbon emissions drop in both markets. In GB, emissions drop from 170MtCO_2 in 2010 to 50MtCO_2 in 2030 – a drop of two-thirds. This leads to an emissions intensity (the amount of CO_2 emitted per unit of generation) falling from 460gCO_2/kWh down to 130gCO2/kWh by 2030. In the SEM, emissions drop from 20MtCO_2 in 2010 to 8MtCO_2 by 2030 – slightly less than a two-thirds drop. In the SEM, emissions intensity starts from a higher base than GB at almost 500gCO_2/kWh, owing to coal and peat plant. However, by 2030, this has fallen to 177g$C0_2$/kWh.

The further nine cases explore other possible outcomes: 'Cap Payment' implements a Capacity Payment in the GB market, 'Lower RES' which examines a lower renewables target; 'Carbon drop' where the carbon price is reduced; 'IED' examines the implications from a strict implementation of the Industrial Emissions Directive; 'Offshore deployment' increases offshore wind deployment; 'Severn Barrage' examines the implications of a 10GW tidal generation; 'Interconnection' where less interconnection between GB and the SEM is assumed; and two demand management scenarios which investigate the implications of demand management.

Conclusions and findings

A world with significant intermittent generation is no longer a world of averages

Our analysis clearly shows that in a system with significant volumes of intermittent generation, extremes become increasingly important rather than average conditions. Indeed, 'an average day' becomes a meaningless concept when wind generation could be contributing all of generation or nothing. 'Extreme' days or hours become much more normal, as price spikes, significant changes in generation patterns, or indeed significant overcapacity, occur much more frequently.

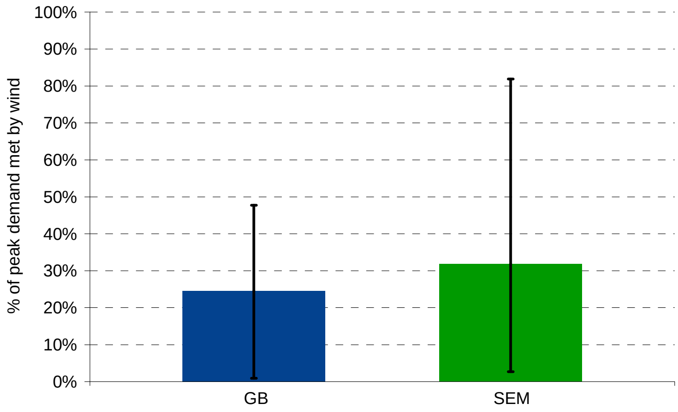
Periods of very low wind generation (less than 5% of installed capacity) across either GB or Ireland will not be uncommon, and may last up to a few days; equally periods with very high wind generation and low demand will exist.

Since the correlation of wind between two points decreases the further they are away from each other, low periods of wind at one location can often be offset by high wind speeds elsewhere. At a distance of about 200km apart (roughly London to Birmingham) there is a correlation (r^2) of around 0.65 between wind farms, whilst by 900km apart (approx London to Aberdeen) the correlation drops to 0.2 – a low correlation.

There is some correlation (r^2 of 0.44) between wind in the SEM and in GB – both do experience periods when average wind speeds (or wind generation) is either very high or very low together. In our base scenarios, there are no periods when wind generation in GB is high (over 90% of capacity) and at the same time low (below 10% of capacity) in the SEM.

Although wind speeds on average do increase during daytime peak hours, and are higher in winter than in summer this is typically masked by a very significant variation of generation around the averages. Figure 1 illustrates the contribution of wind generation in the three peak demand hours across our eight Monte Carlo years. The variation is striking, ranging from 1% - 48% in GB and between 3% - 82% in SEM. These figures illustrate that wind will not necessarily be present when the system is facing highest demand, and suggest that the validity of simple capacity credit assumptions is limited as wind penetration increases to significant levels.

Figure 1 – Percentage of three peak demand hours met by wind generation



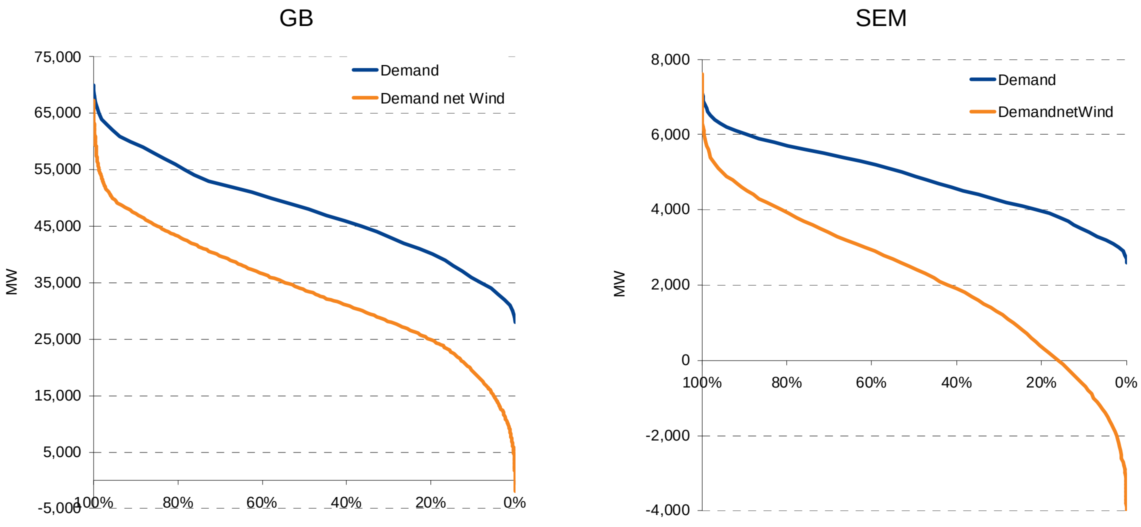
There is some variation in annual wind generation between our eight Monte Carlo years (2000-2007). For 2020 with an assumption of 33GW of wind capacity in GB, there is annual generation of between 83TWh and 93TWh in our eight Monte Carlo years – a variation of 12%. In the SEM, a higher annual variation of 21% is found in 2020 (with 6.1GW of capacity), due to the smaller size of the market – in generation terms this is between 14.6TWh and 17.7TWh.

With high volumes of wind generation, risk in the market increases. We have not created a benchmark of risk, but we find that market prices could jump between -£40/MWh and +£1000/MWh in a short period of time. This may be characterised as both price risk and also (for non-baseload plant) as volume risk. This combination of risk is particularly difficult for generators to hedge except within a portfolio of generation which includes wind.

Wind generation is highly variable and will change the profile of demand supplied by thermal plant

The demand which must be met by non-wind capacity (termed 'demand net wind') will be much more variable than the current demand profile. The duration curves for demand and demand net wind are shown in Figure 2. In GB in 2030, in our Core scenario, demand varies between 30 - 70GW. However, demand net wind varies between 0 - 65GW. In the SEM, there is a similar relationship – the range of hourly demand across the year is 5GW but the range of demand net wind is 11GW.

Figure 2 – Demand duration curves for GB and SEM in 2030



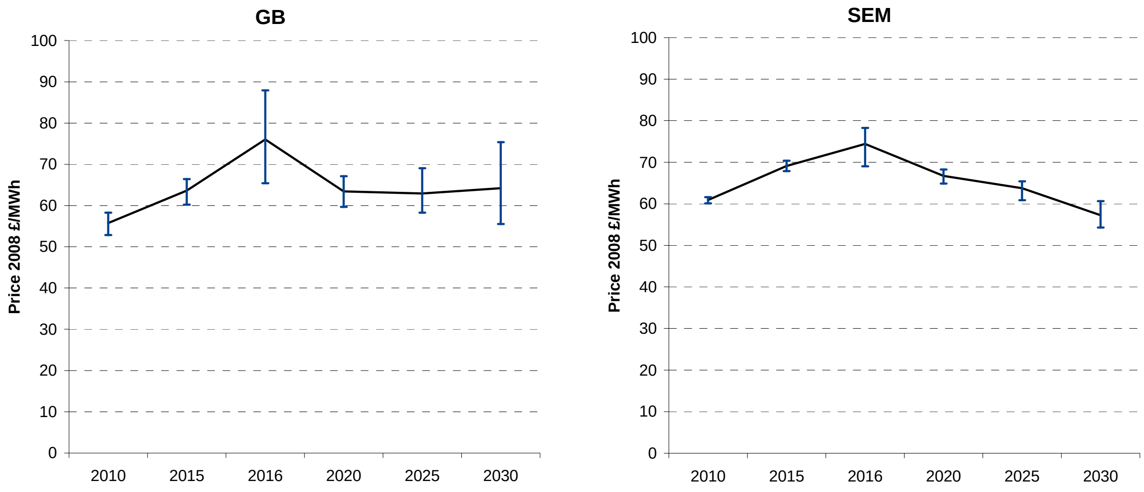
Installed capacity and demand from Core scenario.

Additionally, the potential ramping required by the thermal system will increase. The ramping (hour-on-hour change) for demand net wind is greater than that for demand, and as the installed capacity of wind increases, the ramping will increase. In 2020, the maximum hourly change that non-intermittent generation is found to face is 13GW up, compared to only 11GW with no wind. By 2030, this has increased to 15GW up – thus 15GW of generation has to be brought on line for a single hour in the worst case scenario covered in our analysis. In the SEM, hourly ramping of demand net wind increases from 2.1GW in 2020 to 2.6GW in 2030, compared to 1.1GW with demand only.

Price volatility and price spikes may increase

Annual average prices will become increasingly driven by wind. Figure 3 shows how annual prices vary by Monte Carlo (historical) year for the GB and SEM. For GB in 2010 there is a spread of about £5/MWh between the simulations, but by 2030 this has increased to almost £20/MWh. The spread in the SEM is much smaller than in the GB market, with a range of £1.5/MWh (€1.64/MWh) in 2010 rising to £6.4/MWh by 2030.

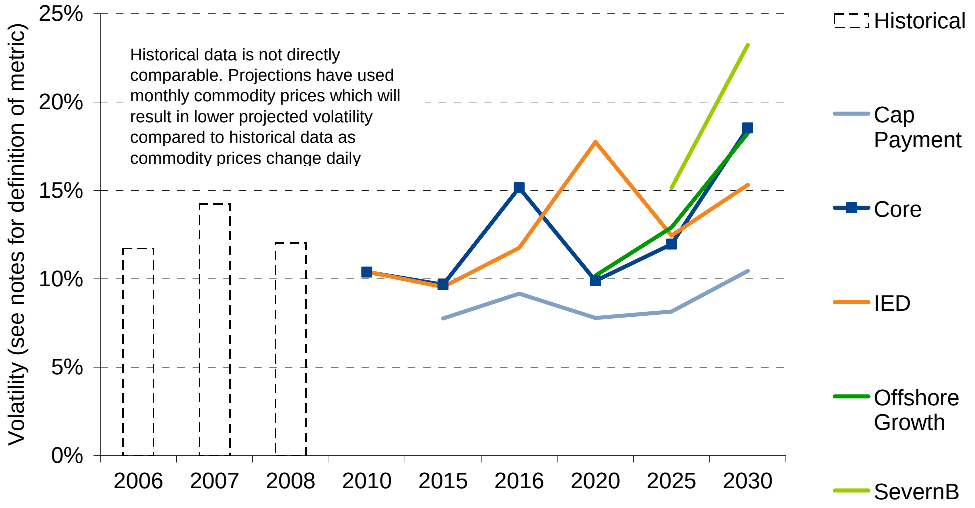
Figure 3 – Annual wholesale prices and spread across Monte Carlo iterations



In GB in the Core scenario with a continuation of the BETTA market rules, prices become much more 'peaky' – increased periods with very high or very low prices. This is because the system will alternate between having too much capacity – in periods with high wind speeds and high wind generation, and much tighter capacity when there are low wind speeds. Equally, the market design in GB means that some very high prices would be required if new generation is to recover its fixed or investment costs. By 2030, with significant volumes of wind on the system, the distribution of prices will change, with periods of negative prices due to the wind generation bidding at its opportunity cost of -1 ROC, periods with low or zero prices and some periods with very high prices above £1000/MWh. Even this does not fully remunerate new-build peaking generators which are required by 2030 to maintain existing levels of security.

As shown in Figure 4, price volatility increases sharply in all scenarios from 2010 onwards. Under the Core scenario we find a sharp jump in price volatility in 2016 as the system becomes tighter with retiral of plant under the LCPD. Volatility then drops, but rises even higher by 2030 as a result of price volatility due to wind generation and higher overall prices due to new entry. In the IED scenario volatility is also high in 2020 due to further retirement of plant in 2020 as a result of the IED (Industrial Emissions Directive). The introduction of a 10GW Severn Barrage has the highest volatility of the cases shown.

Figure 4 – Hourly price volatility in GB



Note: Volatility defined as average absolute change in prices as a fraction of annual average prices.

In the SEM, although prices will become more extreme than currently, they will not be as volatile as GB prices because of the SEM market rules. There will be more low and zero priced periods than in GB due to the higher volumes of wind generation as a share of the market, though (due to our assumed bidding of wind in ROI at zero) very few negative priced periods. The extremes of high prices that GB may experience will be tempered in the SEM due to the Capacity Payment Mechanism, although GB will maintain a strong influence on SEM prices.

Periods of zero and negative prices may increase and average prices may fall

In GB, the Core scenario has no low priced periods in 2010, but by 2020 there are a few periods when prices are zero or negative. By 2030, the combination of nuclear, CCS, biomass and wind would create over 70 periods a year on average where prices are less than -£30/MWh. Equally, the number of periods when prices are between £0-10/MWh increases substantially to 280 – about 3% of the year.

In the SEM, there are much fewer negative priced periods as wind is modelled to bid at marginal costs (assumed in ROI to be zero). In 2030 there are only 28 periods when prices drop below -£30/MWh (-€32.7/MWh). There are, however, many more low priced periods in the SEM due to the higher wind penetration and smaller market size – thus in 2030, there are over 700 hours when prices are between £0 and £10/MWh, and over 1000 hours when prices are below £20/MWh.

Table 24 shows the number of hours in which prices drop to low levels in selected scenarios, split by price bands.

Table 1 – Periods of low prices by band in GB and SEM – Core scenario

Count of hours when prices are: (£/MWh)

		< -30	-30 to -20	-20 to -10	-10 to 0	0 to 10	10 to 20
GB	2010	0	0	0	0	0	0
GB	2020	0	0	0	0	6	1
GB	2030	73	3	0	0	280	48

Count of hours when prices are: (£/MWh)

		< -30	-30 to -20	-20 to -10	-10 to 0	0 to 10	10 to 20
SEM	2010	0	0	0	0	0	0
SEM	2020	0	0	0	0	83	3
SEM	2030	29	3	0	0	699	249

Across all the scenarios and years we find that in GB, an increase of 10TWh of wind generation (around 3-4GW of wind capacity) reduces prices by about £0.6/MWh, whilst in the SEM (given an assumption of 1.4GW of interconnection) an increase of 10TWh reduces prices by £7/MWh (€7.63/MWh). An increase of 10TWh of wind generation is a much greater share in the SEM than in GB, which explains the greater impact.

Average within-day price profiles remain broadly similar as wind generation increases, with the pattern of lower prices overnight and higher prices during the day. However, the variance around these prices becomes much greater.

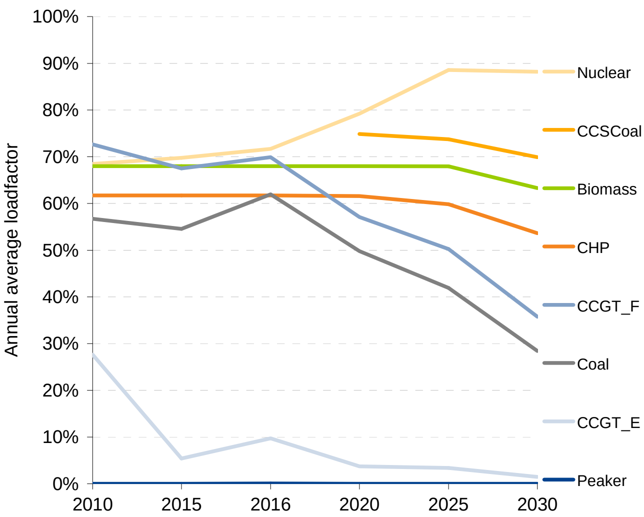
Plant operation profiles may change

Load factors of conventional thermal plant are strongly impacted by high volumes of wind and baseload generation. Figure 5 and Figure 6 reveal the detail. In GB by 2020, load factors of older E-class CCGTs[1] are below 10%, and newer F-class plant are under 60% whilst coal is at 50%. The main reason for this is the reducing ‘space’ for these plant to operate in – with rising volumes of baseload nuclear, CCS coal and biomass plant, and increasing volumes of low-cost intermittent generation, the running patterns of conventional plant by 2020 are increasingly the inverse of wind generation.

[1] E and F-class CCGTs refer specifically to GE manufactured machines, but are used within this report to denote older (E-class) and newer (F-class) designs.

Figure 5 – Load factors for GB plant in the Core scenario

Plant load factors in GB

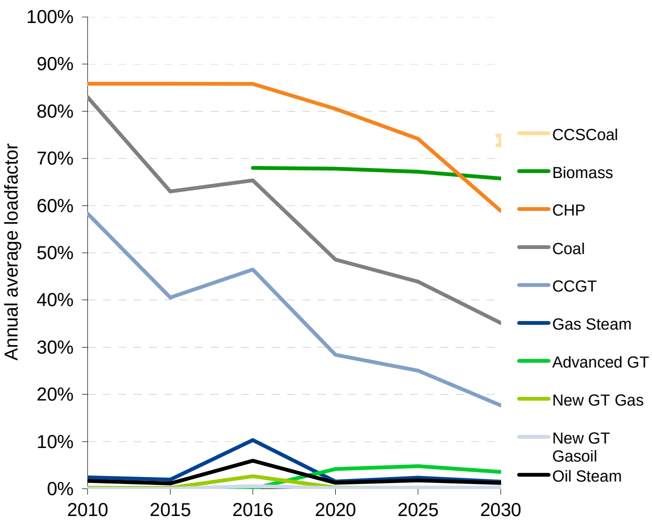


Plant load factors in GB

	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	63%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	28%	5%	10%	4%	3%	1%
CCGT_F	73%	67%	70%	57%	50%	36%
Coal	57%	55%	62%	50%	42%	28%
Gas Steam	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Old GT Gas	0.0%	0.1%	0.1%	0.0%	0.0%	0.1%
Old GT Gasoil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New GT Gas	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New GT Gasoil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oil Steam	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 6 – Load factors for coal plant in the SEM in the Core scenario

Plant load factors in the SEM



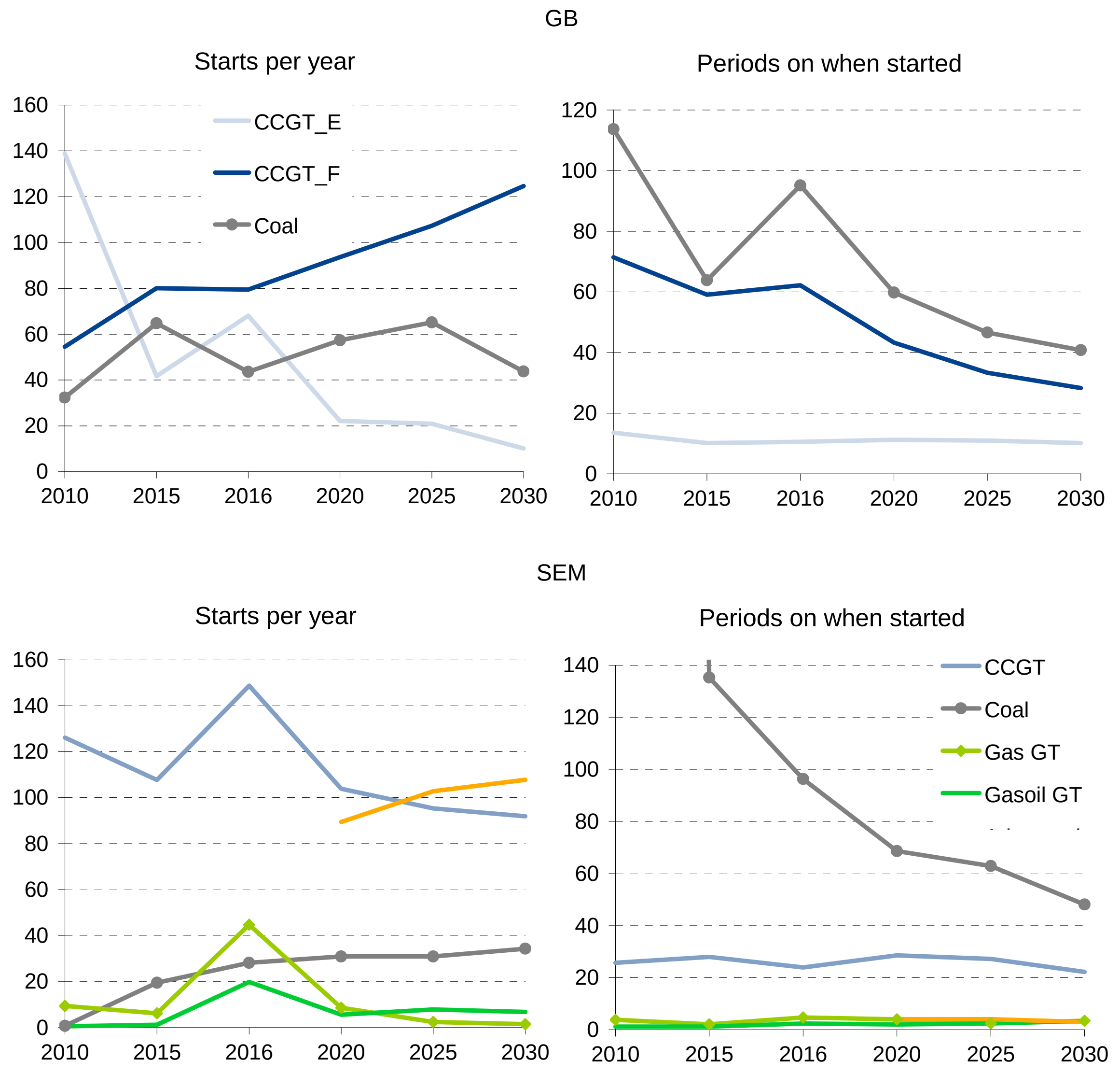
Plant load factors in the SEM

	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						74%
CHP	86%	86%	86%	81%	74%	59%
Coal	83%	63%	65%	49%	44%	35%
CCGT	58%	41%	46%	28%	25%	18%
Gas Steam	2.4%	1.9%	10.3%	1.5%	2.4%	1.5%
Advanced GT	0.0%	0.0%	0.0%	4.2%	4.8%	3.6%
New GT Gas	0.2%	0.2%	2.6%	0.2%	0.2%	0.1%
New GT Gasoil	0.0%	0.0%	0.5%	0.2%	0.2%	0.2%
Oil Steam	1.7%	1.1%	6.0%	1.3%	1.8%	1.3%

As regards running patterns, different plant types are affected in different ways, as illustrated in Figure 7. Newer F-class CCGTs face an increasing number of starts and a reducing period when they are on the bars. In 2010, they typically run with 50 starts and are on for around 70 hours (3 days) – this will be running 5 days a week for some units and less for others. By 2020, the number of starts has increased to 90 a year, with units on for only 60 hours. By 2030, they start 120 times a year and run for about 25 hours. However, older E-class CCGTs have fewer starts. In 2010 they typically run two-shift, running for around 14 hours when on and starting 140 times a year. The number of starts then falls as the units are called upon to operate less and less, so that by 2020 they are starting only 20 times a year, and operating 13 hours each time.

In the SEM, the change in coal and CCGTs is much less even though wind penetration is much greater – this is mainly due to the existence of larger amounts of peaking plant. The less efficient peaking plant start 8-10 times a year and are on for 3 to 4 hours, with the advanced GTs starting 100 times a year with similar on times.

Figure 7 – Starts and periods on when started GB and SEM – Core scenario



Figures exclude starts due to outages

GB faces an investment conundrum

A large increase in wind generation introduces a particular concern over the incentives for investment in generation in the GB market, which is an energy-only market with pay-as-bid pricing. Investment in this market relies on a relationship between tight system margins (at times) which delivers market prices above generators' own short-run marginal costs. Our concern is twofold:

- with more wind capacity, there is a sharp increase in the variability of the system margin, which is the basis for the capacity component of price (with fewer hours with a shortage of capacity, but more severe shortages when there is a shortfall); and
- under a pay-as-bid pricing mechanism, generators might find it difficult to capture the full market value of their energy at these (rare) times of shortage.

In all our scenarios, we assume system security is maintained, and sufficient plant is assumed to be built to ensure security margin. In the Core scenario, there is reducing space for thermal generators to operate in, which has strong implications for the returns on new-build. Returns in GB for new build coal and peaking generation are relatively low – around 3% IRRs (pre-tax real) for conventional coal, 6 - 7% for CCS coal and less than zero for peaking plant. Returns on CCGTs when new build is required are at the lower range of our expectations for new build at around 9%. It is notable that nuclear gives the highest return of the plant types shown of between 11 - 12%. This is because it has a low marginal cost so it runs at baseload – a low 'volume risk' – and is rarely displaced by wind, unlike CCGTs. As noted above, in our Core Scenario we assume the build of some OCGT capacity in 2030 which is not economic under existing assumptions.

Interpreted strictly, the energy-only nature of the GB market means that plants earn revenue only at times when they are operating. Despite the adjustment applied to the historical inferred capacity value, some low merit plants (predominantly older CCGTs and new-build OCGTs) still earn insufficient revenue to justify their existence. This leads to 2.4GW of older CCGTs being shut due to their inability to cover fixed costs in 2020. In our Core Scenario we assume the build of around 1GW of OCGT capacity in 2030 in order to maintain system margins and maintain a reasonable range of prices for other plants on the system. Much of this plant is not economic under a strict interpretation of the BETTA market arrangements as they stand, even allowing for the assumed revenue to OCGTs arising from ancillary service contracts. New OCGTs by 2030 are found to operate (on average) for 3-4 hours per year, delivering an annual shortfall of around £34/kW against investment requirements[2]. For example, this implies that ancillary service revenue would have to double to cover virtually all of the costs of these plants, or that captured energy prices would have to rise by in excess of £10,000/MWh above those modelled, for their 3 - 4 hours per year of operation. In practice these revenues would be very susceptible to year-on-year wind variation.

The GB and SEM markets offer a side-by-side comparison of how different market designs can lead to different outcomes. In the SEM, plant returns are markedly different. Due to the market design and an explicit capacity payment mechanism, peaking plant makes reasonable returns – in particular the lower efficiency but cheaper designs. Plant benefit from the high and spiky prices in GB – the SEM 'imports' high prices from GB.

However, in the SEM, the payments for capacity provision mean that peaking and low-merit plant does make a return on investment even if it only generates infrequently. Although the cases tested do not prove this unambiguously, based on our analysis we

2 This assumes annual levelised cost of £77/kW (assuming a 10% pre-tax real rate of return over 20 years and £29/kW annual fixed cost), assumed annual revenue from Ancillary Services of £35/kW per year, and with an annual net contribution to fixed cost derived from the model results of £8/kW

expect that the existence of a capacity mechanism in SEM will lead to a better balance of investment to meet the needs of a high-wind environment than the BETTA arrangements.

We conclude that in order for security of supply to be maintained in GB at current levels without significant involvement by the demand side, there would need to be a material increase in the capacity value accrued especially by peaking and mid-merit generators, compared with that in evidence in today's market.

Wind revenue may be depressed due to 'wind revenue cannibalisation'

Wind revenue cannibalisation describes the phenomenon whereby significant wind generation lowers the revenues achieved by wind farms. This phenomenon is termed 'cannibalisation' as wind generation eats into its available revenue stream[3].

In the Core scenario for GB, in 2010, the wind capture price is higher than the TWA[4] price – as a result of more wind generation in winter months when wholesale prices are higher. By 2016, this has reversed, with wind capturing £5/MWh less than the TWA price, as increasing volumes of wind generation affect peak prices in particular. By 2030, wind captures £13/MWh less than market prices – a significant drop.

In the SEM, in the Core scenario, the effect of wind revenue cannibalisation is similar. In 2010, wind earns above the TWA price as in GB, but by 2020 this has dropped to £5/MWh (€5.4/MWh) below, and by 2030 the gap is £12/MWh (€13/MWh). It is surprising that the effect in the SEM is not greater than in GB as the installed wind capacity is much greater. The reason is that the SEM is heavily interconnected to GB and GB price spikes and dips have a lower correlation to wind generation in Ireland.

The effect varies by differing locations, dependent on their correlation to overall wind generation across the market, and there is a spread of £12/MWh between the different locations in GB in 2030, and £10/MWh in the SEM.

An approximate relationship can be established between the amount of installed capacity and the discount between the TWA price and the capture price of wind generation. For GB, with 10GW installed, wind captures approximately the TWA price. For every further 1GW installed, wind capture prices drop £0.25/MWh below the TWA price.

Reserve requirements may increase, as may requirements for warming

Response characteristics vary for different markets depending on their physical size, which means that different response requirements are binding for GB and Ireland, illustrated by Figure 8. In GB, the binding response requirement is typically secondary low frequency response which covers a drop in frequency due to a plant outage. This constraint is binding (changing system dispatch decisions) for 30% of the time before 2016. With the commissioning of EPRs[5], the N-1 contingency for replacement generation increases to 1600MW which means the constraint becomes more important, binding 70% of the time.

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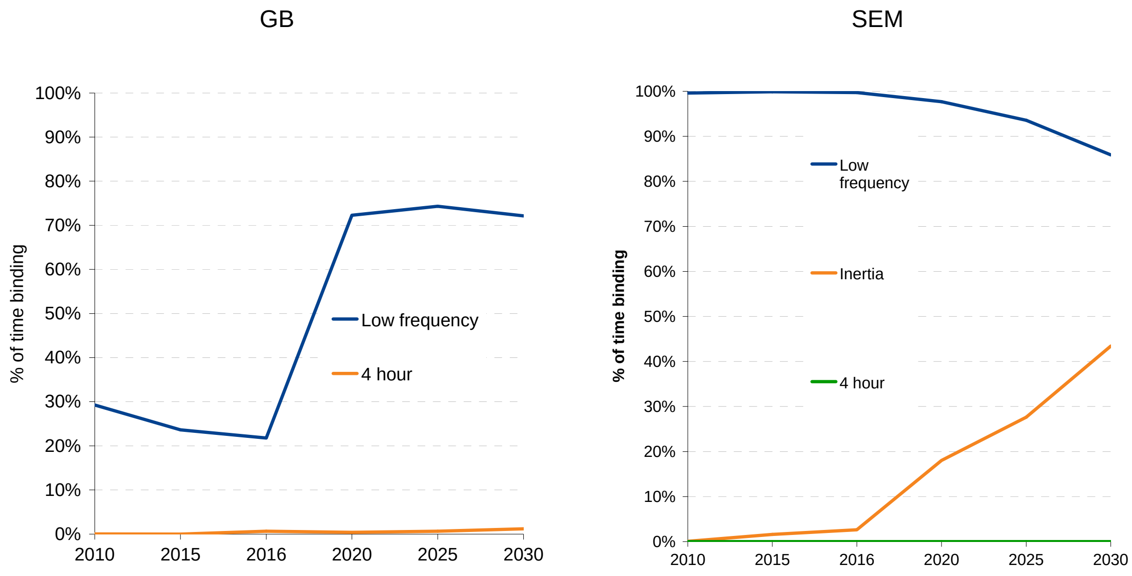
3 This phenomenon is neither new nor restricted to wind generation, but is symptomatic of the competition between any generators with similar costs. It is notable because of the history of wind generators being zero-marginal cost price takers without material influence on the market, and their expected transition to being a significant driver of price.

4 Time-Weighted Average price – the simple average of all hourly prices in a year.

5 European Pressurised Reactors – a modern design of nuclear reactor.

Figure 8 – How often reserve and response constraints bind or are not met



The provision of four hour reserve becomes increasingly significant as wind penetration increases. Assuming a reserve margin of 25% to cater for an average 10% wind output forecast error (the system operator plans for the worst case rather than the average), four hour reserve requirements in GB will rise from 5GW in 2010 to over 10GW by 2030 for January business days, to cover possible errors in wind forecasting. In the SEM, the requirement for four hour reserve rises from 800MW to almost 1200MW by 2030. In the SEM, the four hour reserve is largely met from operating plant or peaking plant held in reserve. As a result, very little less responsive plant needs to be kept warm (so that it can synchronise within four hours). In the Core Scenario for GB, the four hour reserve requirement has to be met in large part from plant that cannot respond when cold in a four hour timeframe, and would have to be paid to be kept warm. The amount of cold plant also rises because load factors of CCGTs fall, and they are off for longer periods of time due to being displaced by wind.

Existing market arrangements in GB will be put under pressure

As noted above, the modelling has recorded the returns which generators would earn in order to justify new build. Our methodology has assumed that sufficient generation capacity will be built in order to maintain existing levels of security of supply, and to consider the implications for market pricing in order that this assumption can be realised. The key issue is that the existing relationship between system margin and the capacity component of wholesale price must change in order that new entry is sufficiently rewarded.

Our modelling assumes that at any given level of system margin the value of capacity is significantly higher than at present (although the average levels on a time-weighted average basis are similar), and assumes that plants operating at the relevant times are able to capture the full capacity value for those hours.

However, these assumptions alone are not sufficient to reward the level of new build peaking generation which is assumed to be required to maintain existing levels of security of supply. In a high-wind system with a large surplus of (installed) capacity over system demand, the number of periods with a narrow capacity margin is far fewer than in a conventional system. Put another way, although there are expected to be high-demand periods with very little wind (requiring backup capacity), these are rare events.

Under a continuation of the pay-as-bid energy-only market, the capture of capacity revenue in these infrequent periods is expected to be more difficult than in today's market, and we anticipate that increased support would be required for peaking and low-merit generation compared with today's market. This could be through a variety of means, including development of the market to include trading of peaking option contracts, increased ancillary service payments or some form of capacity mechanism. Alternatives might include living with a lower level of security of supply or the inclusion of the demand-side in the market in a meaningful way.

A key conclusion is that in order for security of supply to be maintained at current levels without significant involvement by the demand side, there would need to be a material increase in the capacity value accrued by peaking and low-merit generators, compared with that in evidence in today's market.

It should be noted that this analysis does not lead to a firm recommendation for a revised market design in GB incorporating capacity payments. However, it does make stark the differences in outcomes between two different market arrangements and highlights some of the changes which would be required in order to maintain security of supply in GB if the high-wind outcomes are to be realised.

Closing remarks

This study draws on a fundamental modelling process to quantify many of the aspects of intermittency that have largely been the subject of conjecture to date. While it is clear that this approach can examine many issues in great detail it is our view that the impact of the intermittency have not been understood up to this point and that significant structural changes will probably have to be made to reach the current targets for renewable generation and de-carbonisation of the sector.

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1. INTRODUCTION

1.1 Background

There is a consensus across Europe and world-wide that climate change is an urgent problem and that the electricity sector is a key part of reducing carbon emissions. Milestones have been set for the period to 2020 but the continued drive for decarbonisation of the economy will lead to pressure for further renewable and other low carbon generation beyond that time. In the longer term, the UK's government has committed to a policy of 80% reduction in CO_2 emissions by 2050, and the Committee on Climate Change has set out a pathway to this which includes very significant decarbonisation of generation by 2030. Addressing this challenge will introduce a large quantity of generation with technologies which, in large quantities, have the potential to disturb both short-term operation and pricing and longer-term investment decisions in ways which hitherto have not been well understood.

The EU's proposed renewable targets for 2020 imply very significant deployment of renewable generation in the next 11 years, with a target of 15% of final energy use sourced from renewables for the UK and 16% for the Republic of Ireland. This could mean that over 30% of electricity generation will have to be met by renewable energy in the UK, and perhaps 40% in Ireland. Ireland has adopted a renewable electricity target of 40% by 2020, and the UK is in the process of finalising its renewable energy strategy to support the EU renewable energy target.

Our view is that if the renewables and decarbonisation challenges are to be met, the consequent level of uncertainty over market outcomes is greater than at any time since liberalisation of the electricity industry began.

1.2 What is 'intermittency'?

The main new technology built to meet renewables and decarbonisation targets will be wind generation, primarily due to its lower cost compared to most renewables and the fact it is a known demonstrated technology. Proposals suggest that up to 35GW of wind could be on line in the GB system by 2020 (33% total installed capacity) and 6GW in Ireland (43% of total capacity), with the installed capacity by 2030 could be even higher. The most obvious aspect of wind is that it does not blow at a constant rate over time. This creates particular issues for an electricity market and system operation, as conventional generation has to be available and scheduled when there is little wind generation, and dispatched off when there is a lot of wind.

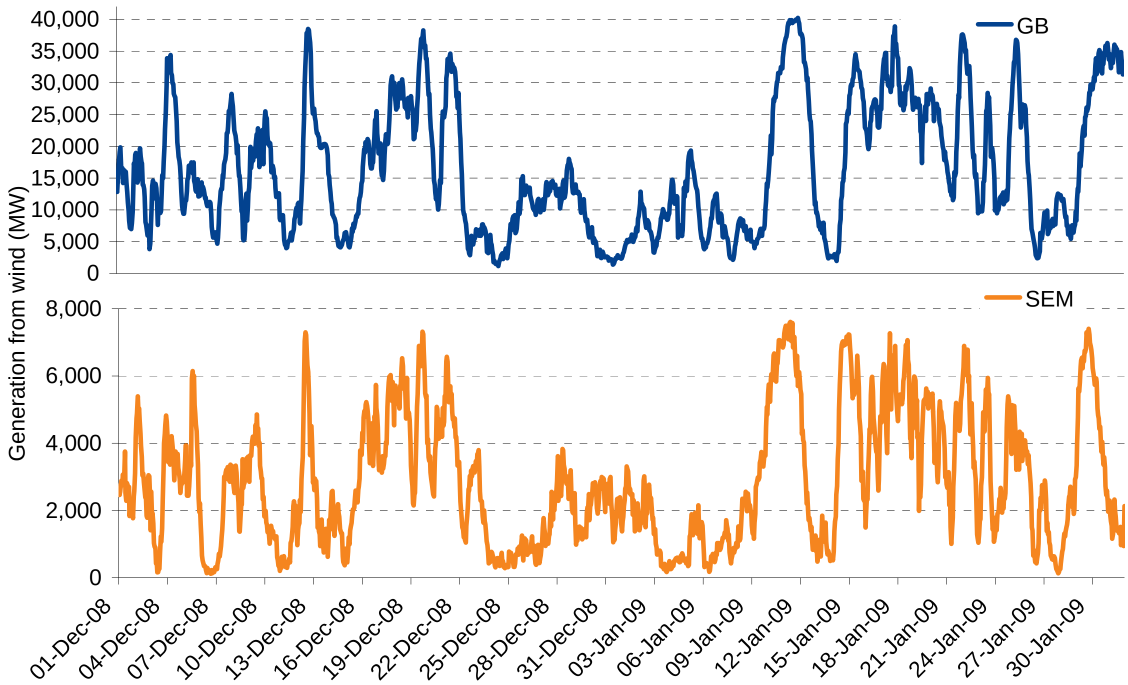
Figure 9 illustrates this effect for the period over Christmas 2008 and into New Year 2009. We take this period of time and extrapolate these weather conditions forward as if the is 43GW of wind generation installed in GB and 8GW in the SEM[6] (the Core scenario in this study in 2030). From about Christmas Day 2008, wind speeds across the British Isles dropped significantly with generation from wind falling to a low of 2.6% of maximum on Christmas Eve at lunchtime in GB and 2.2% in the SEM on 27 December. This period of low winds continued through until the second week in January, coinciding with a period of very cold weather due to a high pressure area which covered most of Europe, leading to very cold days across much of the Continent. In the UK, schools closed and the fountains

[6] Single Electricity Market, covering Republic of Ireland and Northern Ireland

in Trafalgar Square froze. By 9 January, this area of high pressure moved away, leading to three days of much higher wind speeds and wind generation of almost 95% of capacity. However, once again a high pressure area moved in across the British Isles, leading to two further days of very low wind speeds, before wind generation picked up again.

This example from earlier this year illustrates perfectly the challenges that significant volumes of wind may pose to the electricity system, with periods of high wind generation followed by periods of very low generation, rapid changes from high wind speeds to low wind speeds, and potentially extended periods with limited generation.

Figure 9 – Wind generation in GB and SEM (Dec 2008 – Jan 2009 in 2030)



Source: Met Office, Meteo group and Pöyry analysis

However, it is not only wind generation that have the potential to change the shape of the electricity market. Much of the new generation that is likely to deploy in GB in the next 20 years will be fundamentally different to the existing system in three main ways.

- **Price insensitive.** Most new generation planned for a future low carbon world is price insensitive, such as nuclear, coal, CCS and biomass .[7] This means that the amount of generation that will vary its generation in response to price and/or varying demand will decrease significantly. The amount of generation able to flex in response to varying wind generation will reduce significantly.

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7 Although much of this generation may be technically flexible, including new nuclear plant, it is likely that it will be priced in an inflexible manner and make load following a more significant cost

- **Intermittent[8] (unavailable when needed).** Wind, wave and tidal technologies are all intermittent technologies, and exhibit a reliability when needed that is significantly lower than conventional plant. With significant volumes of wind and marine generation, there is much more generation that cannot be guaranteed on the system.
- **Unpredictable.** Predictability describes the extent to which the generation can be forecast. Wind and wave generation are both inherently unpredictable – and the error in a forecast of wind generation increases dramatically as the time interval increases, in the same manner as any weather forecast. (Tidal generation, on the other hand, is extremely predictable – we know the time of high tides accurately for the next thousand years or so).

As shown in Figure 10, a system that was dominated by price sensitive, non-intermittent and predictable technologies could be changing to one which is fundamentally different. Nuclear, biomass and CCS coal generation all have economics that rely on continuous baseload operation. Although these plant may be able to vary their generation in response to demand, it is usually not economic to do so. Additionally, wind and marine generation is intermittent, and will not necessarily be available when required. Lastly, wind and wave generation are difficult to predict and forecast.

It is not a single one of these attributes that will cause significant issues for the electricity system of the future. Rather it is the confluence of the three together which has potential to radically alter the existing wholesale electricity market, across all timescales from investment in generation and network infrastructure to real time system operation. In particular, a system with very large amounts of wind, wave and tidal generation requires lots of flexible price-sensitive generation to provide back-up. However, much of the non-wind and marine generation that is likely to be built will be nuclear, CCS coal and biomass, all of which are designed and financed to function at baseload (continuous) operation, and can provide only limited flexibility. There is a distinction between commercial and technical flexibility – a unit may be capable of providing significant flexibility, but may choose not to do so due to the underlying economics and market design.

Thus the driver for the 'intermittency issue' is not wind per se, but the combination of large volumes of unpredictable intermittent generation and large volumes of inflexible generation replacing a system that currently is dominated by flexible, load following and predictable plant.

8 The term 'intermittency' is regarded by some as a pejorative term – and terms such as 'variability' have been proposed as a more accurate description of wind generation patterns. Given that 'intermittency' has become the most widely accepted term across the industry, Pöyry has chosen to use this, and regards it as descriptive rather than pejorative. It is also observed that all generation types are not wholly reliable – even the best new technology might achieve availabilities in the low 90%'s and many plant have availabilities at 70%. However the availability of wind generation is significantly lower than this – hence the distinction of intermittent generation.

Figure 10 – A fundamental shift in generation characteristics by 2020

	Gas/ coal	Nuclear	Wind	Wave	Tidal	CCS	Biomass
Price insensitive?	✗	✓	✓	✓	✓	?	✓
Intermittent (unavailable when needed?)	✗	✗	✓	✓	✓	✗	✗
Unpredictable?	✗	✗	✓	✓	✗	✗	✗

Note: It is not clear how CSS will operate in the future, as the technology is not yet deployed on a commercial scale. However, it appears likely it will be much less flexible than non-CCS coal or gas plant.

The issues associated with this change extend from prices and risk in the wholesale market, and what sort of new entry could be expected to fundamental questions about market design.

These issues are most critical for areas such as the UK and Ireland which are lightly interconnected, with little hydro capacity (a natural balance to wind generation) and which enjoy significant wind resource. Other areas of Europe will share these concerns but none has the potential to be hit so hard or as immediately as the island of Ireland and (to a lesser extent) GB. Under current policies, Ireland faces levels of wind generation which are effectively unequalled in Europe[9]. Although wind generation in GB is expected to be proportionately less than for Ireland, the concerns for GB relate to its relative electrical isolation from the larger UCTE continental system[10], the operation of its market arrangements and the potential development of new nuclear generation which shares some of the inflexible attributes of wind generation.

It should be noted that difficulties that arise due to intermittency are fundamentally economic in nature – none of the issues we highlight are in any way insurmountable or unsolvable, but all imply additional costs and changes in the way the system is managed.

1.3 Objective of study

Given the potentially profound shifts that may occur in the electricity market, the overall objective of this report is to answer the question:

9 Denmark has proposed a target of 50% wind generation by 2025, but this is mitigated by the extent of its interconnection, notably with the remainder of the Nordel area which has high levels of hydro capacity. Reference 'A visionary Danish energy policy', published 19 January 2007.

10 Proportionally, GB has less interconnection than Ireland.

'How could the impact of intermittent generation, required to meet targets for renewables and decarbonisation of generation, affect the wholesale energy markets in GB and Ireland?'

The study has looked at a series of key aspects to this question:

- **Market prices.** To what extent will market prices change, and how will volatility increase?
- **Plant operation.** How will plant load factors, starts and on times be affected by intermittency?
- **New thermal generation**. What is the outlook for new thermal generation?
- **Wind revenue**. To what extent is wind revenue depressed by wind-on-wind competition?
- **Reserve and response.** How do requirements for reserve and response change and what are the implications?
- **Interconnection and transmission.** How important is interconnection and how are future flows impacted by wind?
- **Market arrangements.** Are existing arrangements fit for purpose?

We have not in this study taken a view on whether the 2020 targets for renewables and subsequent plans for decarbonisation of generation are met in the UK or Ireland. Rather the purpose of this study is to explore the consequences for the electricity markets as the generation sector moves increasingly to renewable and other low carbon technologies.

The backbone to answering the main question is a sophisticated computer modelling tool ('Zephyr'), backed by a wealth of historical data on hourly wind, demand and generator availability, which has allowed simulation of different scenarios of the GB and Irish market. This model has been designed specifically to allow detailed examination of the electricity markets, as it examines hourly electricity prices (365 x 24 hours per year) for a series of 8 'mini-Monte Carlo' simulations which simulate differing patterns of demand, wind and plant availability. These 'mini-Monte Carlo' simulations use consistent demand, availability and wind data for eight historical years, ensuring that the highly complex interactions between weather, availability and demand are correctly accounted for. Thus to examine a single year, a total of 70,080 hourly prices are generated (8760 hours x 8 Monte Carlo simulations), which capture a large part of the variation that could be expected.

The large part of the study has focused on examining a Core scenario, which has been agreed with the Founders of the study. It should be noted that the Core scenario does not represent a Central case or 'best view' of the future world, nor does it represent the views of either the Founders or Pöyry on the most likely future scenario. Rather it represents a starting point, with simple commodity price assumptions, to understand how the future electricity system may evolve. A series of 9 further cases have been modelled to understand the impact of changing certain assumptions.

For the Core scenario and other key cases, we have examined a 'Market Schedule' and a 'System Operator Dispatch (SO Dispatch)'. The Market Schedule run derives prices and the operation of plant without transmission and reserve/response constraints – this represents an hour or day-ahead market. Where of interest, we run a SO Dispatch simulation[11], which accounts for reserve and response constraints as well as 'north-south'

[11] We have only run the SO Dispatch simulation for the Core scenario.

transmission constraints between Northern Ireland and the Republic of Ireland and between England and Wales and Scotland – representing some of what a System Operator would do to ensure the system remains stable.

The analysis spans the period until 2030, with the years 2010, 2015, 2016, 2020, 2025 and 2030 modelled. This means the study captures the effect of a material nuclear new-build programme as well as the possible impact of a Severn barrage.

The study covers both the BETTA market in GB and the SEM which encompassed Northern Ireland and the Republic of Ireland. Arguably, Ireland leads GB in terms of policies and the actual impact of wind generation; with 1000MW of wind connected, Ireland has already seen periods of (near-) zero prices[12] and wind generation in Northern Ireland has been reduced in order to permit conventional generation to remain above its minimum stable generation.

This work builds on previous studies, including research from UK ERC, and studies commissioned by BERR (now DECC) for the Renewable Energy Strategy Consultation.[13]

1.3.1 Areas for further work

At the commencement of the study, there were certain elements that were considered out of the scope of the study, which could not be committed to from the outset. However, many of these could be addressed in further work in the future, if required.

- **Detailed modelling of transmission network.** A line-by-line model of the transmission system would require a significantly different modelling framework. As a result, the study uses a simplified zonal approach, only considering 4 zones – England and Wales, Scotland, Northern Ireland and Republic of Ireland.
- **Post-gate closure issues.** The study has not examined post-gate closure issues, including the impact of unforeseen generator failure and the impact of inaccurate demand and wind forecasts, and as a result has not modelled the Balancing Mechanism.
- **Forecasting accuracy.** The study has not examined the impact of improving forecast accuracy for demand or wind generation. The modelling approach assumes a provision for reserve to cover forecast error, but does not test the effect of forecast error on market prices (for example how forward curves would change as data on wind generation improves closer to real-time).
- **European super-grid and pan-European modelling**. Assumptions for interconnector flows between GB and Europe have been made based on our pan-European modelling work, assuming a profile of hourly prices in interconnected countries, and capacity assumptions for those interconnections. However, modelling the implications of intermittency on the entire European network is considered to be a large undertaking that was outside the scope of the data and the model used.

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12 On 22 October 2008, the Shadow Price in Ireland was zero (set by hydro plant) for three consecutive periods due to high wind in low demand periods. Northern Ireland effectively had a 'curtailment' event (although that definition does not formally exist) on 2 September 2008 in which wind generators were instructed to reduce output.

13 'Implementation of EU 2020 renewable target in the UK electricity sector: Renewable Support Schemes', Redpoint, June 2008. 'Growth scenarios for UK renewables generation and implications for future developments and operation of electricity networks', SKM, June 2008.'The costs and impacts of intermittency' UK ERC, March 2006.

- **Effects of climate change.** Climate change may have impacts on weather patterns, electricity demand and other factors. It is considered that these are beyond the scope of the study.
- **Dynamic or optimal investment.** Although this study examines which types of investment are best suited to the world of intermittency, what happens given various profiles of investment, and assumes that investors are (reasonably) rational, it does not attempt to create an 'optimal' view of new investment.

1.4 Study structure

The study has been funded by a large group of participants who have taken part either as 'Members' or 'Founders'. Study Founders have participated on the Steering Group, giving direction to the study and providing an external opinion on the work. The six study Founders include the system operators for both markets, major utilities and wind developers. The Members of the study include utilities and regulatory and government bodies.

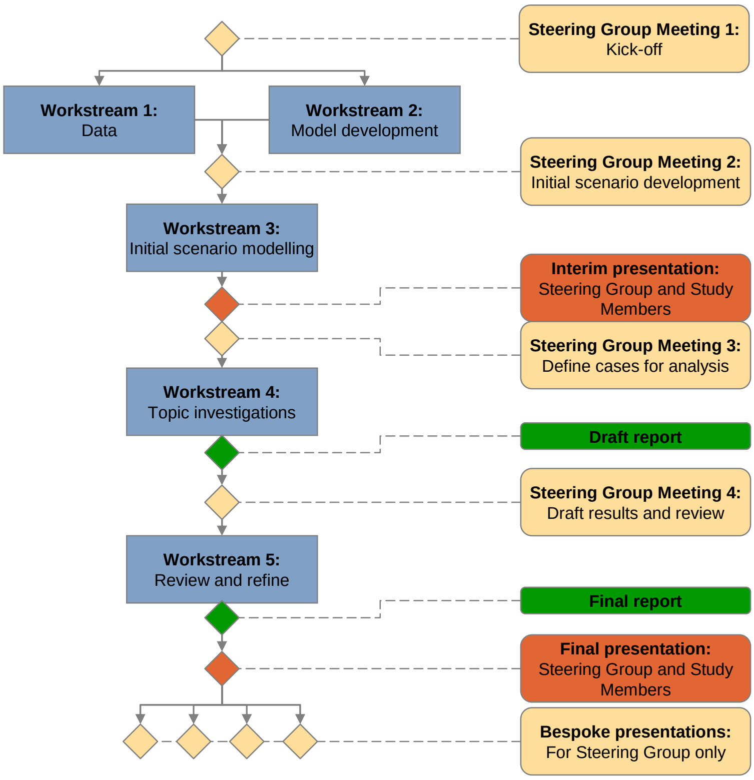
The Founders have provided significant support in terms of data, interpretation and modelling methodology, in particular for wind output and reserve and response requirements, through a combination of the Steering Group and informal Working Groups. This collaborative approach has delivered a degree of credibility, a robust model and underlying dataset which we believe is unparalleled.

The results of the study represent the views of Pöyry and are not necessarily representative of the views of individual Members or Founders of this study.

Figure 11 shows the programme of work for the study, which was structured into 5 workstreams:

- **Workstream 1 – Data.** This workstream focused on providing the large data sets that were required for the modelling. In particular, this was demand, availability and wind data for GB and Ireland.
- **Workstream 2 – Electricity market model development.** This workstream developed the 365-day Mixed-Integer Linear Programming (MILP) platform that was used for the underlying modelling.
- **Workstream 3 – Initial scenario modelling.** This workstream modelled the first cut of the Core scenario to begin to understand which elements would be most important to focus in on the Topic Investigations.
- **Workstream 4 – Topic investigations**. Following the analysis carried out for the initial scenarios, this workstream investigated the core questions agreed with the Steering Group, through a series of modelled scenarios, other quantitative analysis and qualitative work.
- **Workstream 5 – Write, review and refine.** This workstream completed the final report and the refinements required on it.

Figure 11 – Programme of work



1.5 Report structure

This report is divided into seven main sections, a Glossary, and (as a separate document) Appendices.

- **Section 2 – Overview of methodology.** This covers an overview of the methodology used, including a high level description of the model and the data used. In addition there is a discussion on the value of capacity and how it has been implemented in GB and the SEM.
- **Section 3 – Wind and wind generation in GB and Ireland**. This discusses wind generation in the two markets – examining how often there are low wind generation periods, how correlated wind is across the UK and ROI and how accurate our simulation of wind generation from wind speed is compared to actual wind generation data.
- **Section 4 – Core scenario.** This gives an overview of the inputs and results from the main scenario used in this study – the Core scenario. This scenario has been designed to understand the 'implications of intermittency' and does not represent a Central or Base view of the future.
- **Section 5 – Summary of further cases**. This covers the other cases run as part of the study, highlighting the differences in inputs and some of the results.
- **Section 6 – Topic investigations.** This is the heart of this report. In it, we answer a series of key questions that were posed at the beginning of the study regarding how a future world with high levels of intermittent generation might look like.

- **Section 7 – Conclusions**. This covers the main findings from the study.
- **Annexes.** These cover more detail on the model and structure, information on the backcast of the model, detailed results for each scenario and further information on the wind methodology used.

1.6 Overview of scenarios

For ease of reference, Figure 12 gives a summary of the scenarios that have been run as part of the study.

Figure 12 – Summary of scenarios

Scenario	Key question	Description
Core scenario	What is the impact of intermittency on the markets of GB and SEM?	High deployment of wind and baseload generation in GB and SEM
Capacity payment scenario	If a capacity payment mechanism existed in the GB market, how might it change outcomes?	The capacity payment mechanism in the SEM is implemented in the GB market
Lower RES scenario	How does a less stretching renewables case affect our results?	In GB there is 6GW less wind in 2020 and 15GW less in 2030 than in the Core scenario, and 1.5GW in 2020 and 3.5GW less in 2030 in SEM
Carbon drop scenario	To what extent are the results changed with a different coal-gas relativity?	The carbon price is reduced to £20/tCO_2 from £35/tCO_2 in the Central case
IED scenario	How does a strict implementation of the IED change the requirements for new build?	5GW of coal and 8GW of CCGTs close in 2020 in GB in additional to those closed in 2016 due to the LCPD
Offshore deployment sensitivity	Does more geographically concentrated wind build with significant deployment on the Dogger Bank affect the market?	Increased deployment on Dogger Bank from 6GW to 13GW, with reduced deployment elsewhere
Severn barrage sensitivity	How does a 10GW barrage affect the market?	Scenario assumes the 1GW Shoots barrage and another 1GW scheme with the same profile is replaced by a single 10GW Cardiff-Weston barrage
Interconnection sensitivity	What is the impact of a smaller interconnection between GB and Ireland	Scenario assumes 400/80MW Scotland to NI and 500MW both ways ROI to E&W
Inflexible demand management scenario	How does a flatter demand profile from inflexible Demand Side Response change our results?	Assumes an increase in electric heating and electric vehicles that leads to a flatter demand profile
Price responsive demand management scenario	How would price responsive demand side management (smart meters) change our results?	Scenario assumes deployment of smart meters which allow dynamic load management

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2. OVERVIEW OF METHODOLOGY

2.1 Underlying principles

The aim of the modelling is to represent as accurately as possible the current and future electricity market in GB and Ireland, through a detailed electricity market model (Zephyr). There are a number of key principles that underlie the modelling approach.

- **History as basis.** The relationships between the weather, demand for electricity, availability of plant, and wind speeds are extremely complex and critical to an accurate analysis. To ensure that this relationship is correct, this study been based on consistent years of historical data for demand, plant availability and wind. This ensures that, for example, a cold day in January caused by a high pressure area north of Scotland correctly matches demand (driven by temperature and wind) and wind speeds (low in Scotland, possibly higher further south).
- **Mini-Monte Carlo approach.** To accurately model a single year, a Monte Carlo approach has been used, which uses a number of iterations to examine the probability of events happening. Due to the detail of the Zephyr model, a full Monte Carlo approach incorporating thousands of iterations is not possible. We have chosen to run a 'mini-Monte Carlo' with 8 iterations which cover the wind, availability and demand from 2000 to 2007. This ensures that the model picks up a representative share of (for example) peak demand coinciding with low or high wind generation.
- **Fully competitive market and marginal cost bidding.** All plant are assumed to bid cost reflectively, and when operating will fully cover their fuel, start-up and part-loading costs. This reflects a fully competitive market which leads to a least-cost outcome. It is also assumed that new thermal plant will make high enough returns over their commercial lifetime to justify their investment, and existing plant will cover their fixed costs.
- **Market Schedule and Dispatch runs**. The modelling has been split into two elements. First is a market schedule run, which derives prices and the operation of plant without transmission and reserve/response constraints. Where of interest, we run a Dispatch simulation[14], which accounts for reserve and response constraints as well as transmission constraints between NI/RoI and E&W/Scotland.
- **Cost recovery**. One way or another, market forces will lead over time to the recovery of both fixed and variable costs of generation; and also, where there is a persistent need for new capacity, the recovery of the capital costs of developing it efficiently.[15]

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14 We have only run the SO Dispatch simulation for the Core scenario.

15 The principle of capital cost recovery is not applied for all types of capacity. Our analysis has assumed levels for renewables and nuclear and is not premised on the requirement that these specific types make a reasonable return in the market. Also, it is difficult for peaking plant to recover its capital costs in the absence of a capacity payments mechanism. Our analysis demonstrates that a significant quantity of peaking plant would be required – we have over 1 GW of new peaking plant in the Core scenario in Great Britain – but we have not been explicit as to how this peaking plant would be remunerated in the BETTA market.

- **Value of capacity.** The value of capacity that is used in the modelling, which represents the scarcity value of capacity, has been based on historical profiles. This is explained in detail in Section 2.5

2.2 Description of Zephyr

Zephyr is a bespoke model that has been developed specifically for the intermittency project, building on our 15-year experience of modelling the European electricity markets.

The model simulates the dispatch of each unit on the GB and Irish systems for each hour of every day – a total of 8760 hours per year. The model is based on a mixed-integer linear programming platform. This allows us to optimise to find the least-cost dispatch of plant accounting for fuel costs, the costs of starting plant and the costs of part-loading, in aggregate. For example, it may mean that the model will reduce the output of wind generation to avoid shutting down a nuclear plant and incur the cost of restarting it later. The model also accounts for minimum stable generation and minimum on and off times, which allows more realistic operational simulation of plant such as large coal or nuclear sets that, once running, must remain on for a certain number of hours, or, once shut down, cannot restart for a long period.

For each future year that is modelled, 8 iterations are carried out, which represent the wind, availability and demand for the historical years 2000 - 2007. This means that for any given future year, a total of 70,080 prices are created (8760 x 8), giving a good representation of possible interactions between wind, availability and demand. The prices that result from the model are the result of the interaction of supply and demand in any given hour.

The model optimises the use of pumped storage, so that it generates when prices are high and pumps when prices are low. The model also accounts for interconnection between GB and Ireland, so that flows between the two countries are optimised. Interconnection flows between GB and Continental Europe are modelled with an hourly price profile of the Continental countries, based on the underlying commodity values and prices from our pan-European Eureca model.

Generation from wind is based on actual hourly wind speeds at 35 locations across the UK and RoI plus an offshore site using 'reanalysis' of wave data, which are converted to generation using an aggregated power curve. This is explained in detail in Section 3.

Figure 13 – Overview of Zephyr model framework

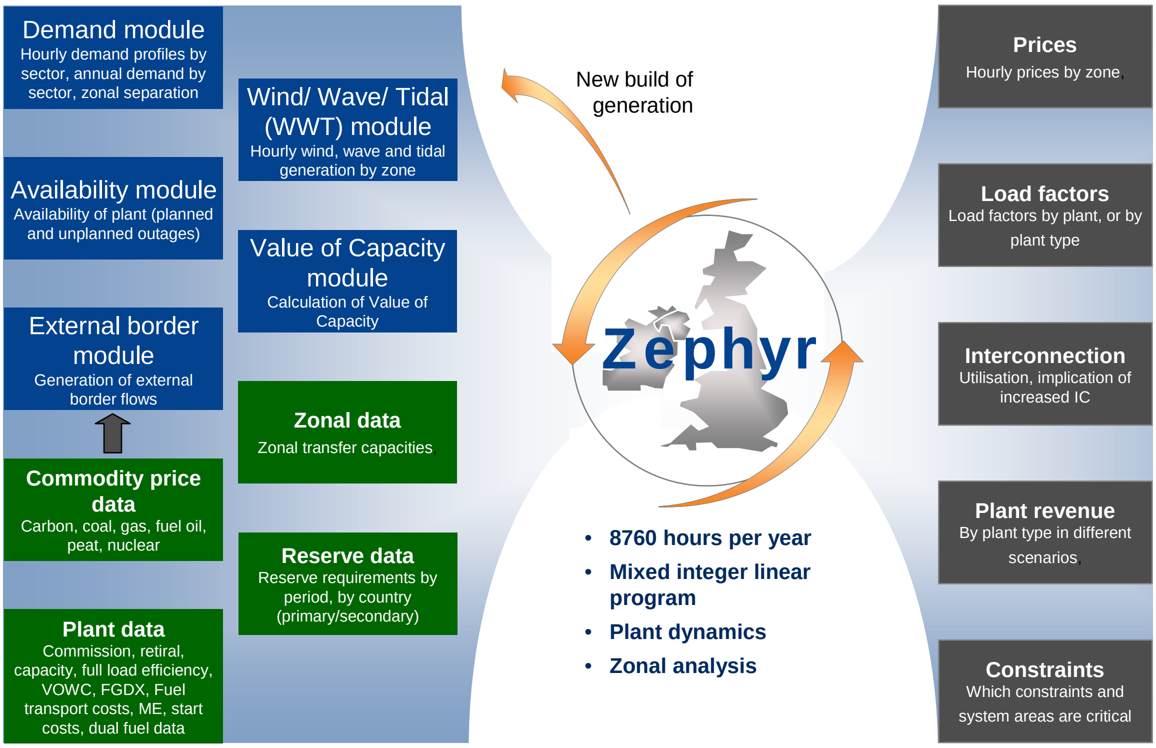


Figure 13 above illustrates the model structure. The inputs to the model can be classified under the following headings:

- demand and availability;
- wind, wave and tidal;
- commodity prices;
- value of capacity;
- plant data; and
- zonal and reserve data.

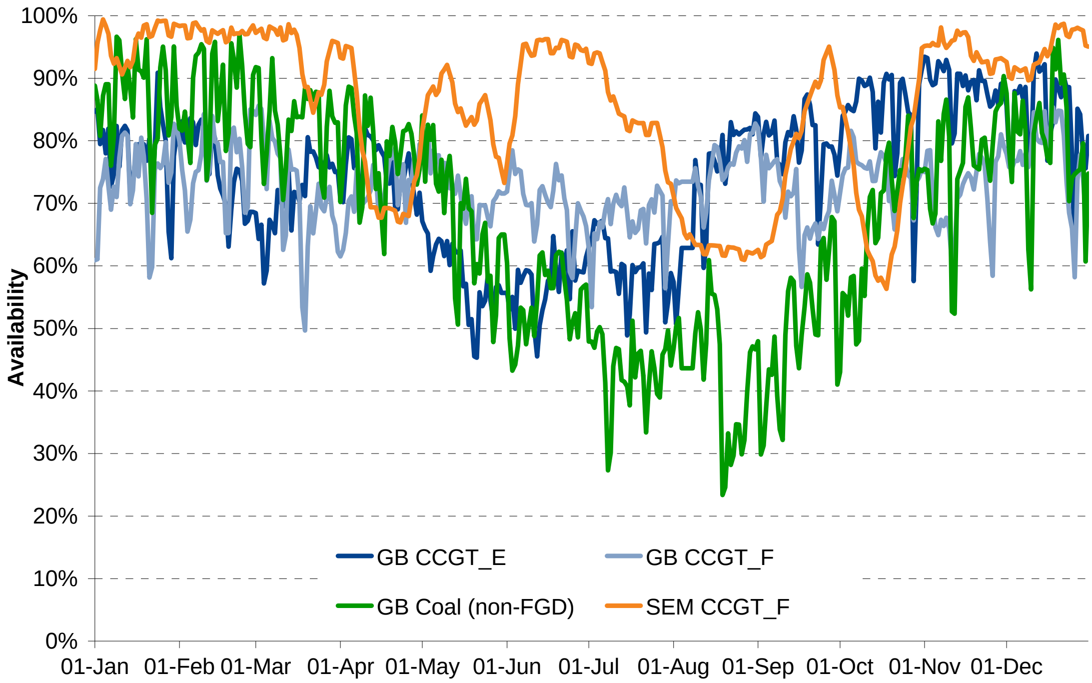
The underlying assumptions are explained in the subsequent sections, and further detail on the assumptions is included in the Appendices.

2.3 Demand and availability

The hourly profiles of demand have been taken from National Grid and EirGrid data for demand from 2000 to 2007. Each annual profile is used in a separate Monte Carlo iteration. Thus peaks and troughs in demand will occur at different times in different iterations.

For GB, demand reported by National Grid is based on all generation that is registered as a BM unit. Thus generation (and the associated demand) that is embedded in the distribution network is not included. We have increased the National Grid demand figures to account for the profile of embedded generation – and hence in Zephyr, embedded generation and its associated demand are both accounted for. This means that the scenario construction is insensitive to whether any future growth in generation capacity is connected to the transmission system or the distribution network. With significant growth in wind and CHP in particular, a lot of new generation may be distribution connected.

Figure 14 – Sample availability profile



For GB, the availability data was taken from half-hourly Elexon[16] data for 2004 - 2007. Earlier years were modelled using 2004 - 2007 data, offset to maintain weekend/holiday period alignment. For the SEM for 2003 - 2007, weekly availability data from EirGrid has been used, with interpolation to give daily values. For 2000 - 2002, the data from 2004 - 2006 has been used, offset to maintain weekend alignment.

2.4 Wind, wave and tidal data

To ensure a consistent set of input data for wind generation, we have worked with the UK Met Office to define 28 sites across GB that offer an accurate representation of future wind generation in the UK. These points are shown in Figure 15, and were chosen to represent sites where there is likely to be significant wind turbine deployment in the next 20 years based on known applications and licensing areas determined by the government. We have obtained 8 years of data from 2000 to 2007 for all these sites based on wind speed measurements from meteorological masts, with missing data in filled by the Met Office. For offshore sites, the Met Office provided 'reanalysis data' derived from a wave model, which has allowed consistent wind data to be obtained for offshore sites such as Dogger Bank, the Wash and the Irish Sea.

16 We have used half-hourly data for Maximum Export Limit for each registered BM Unit.

For the ROI, we have obtained hourly wind speed data from the Met Éireann for 9 sites for the same 8 years.

In total, we have used 2.4 million hourly wind speed records to generate a comprehensive view of future wind generation in the UK and ROI. This allows simulation of any possible future deployment of wind turbines across the UK and Ireland, whether they are offshore, onshore, in Scotland or further south.

Figure 15 – Location of wind sites chosen

For tidal data, we have used profiles provided by DECC for the Shoots barrage or the Cardiff-Weston Barrage. Both barrage profiles follow the twice daily tides, with two peaks in generation and two troughs with no generation per day, and an additional monthly cycle (neap and spring tides) due to the phases of the moon. These profiles are shown in the Appendices.

Wave profiles have been generated based on a Geometric Brownian Motion (GBM) process adjusted for maximum and minimum generation and a seasonal profile. The hour-by-hour variation has been taken from data from a study commissioned by the Carbon Trust 'Variability of UK marine resources'[17].

2.5 Market prices, value of capacity and capacity payments

This section provides an overview of how we have implemented a Value of Capacity in modelling, which is key to understanding how wholesale prices may develop into the future.

In a functioning electricity market, wholesale prices need to cover two elements:

- **variable costs** (largely for fuel and carbon) incurred by generation sets in the production of electricity; and in particular the variable costs of the most expensive set operating at any point in time, with allowance for unit inflexibility, part-loading, and the costs of starting generators; referred to as the System Marginal Price (SMP); and
- **fixed year-on-year costs** of keeping sufficient plant open to ensure that demand is met in peak periods; or, in circumstances in which there is an impending shortage of capacity, the cost of bringing forward new entry (this is discussed further below); we term the additional revenue required in excess of SMP as the value of capacity (VOC).

A sustainable investment equilibrium is reached when existing plants recover their annual fixed costs of operation and (at times when new build is required) when new plants are expected by potential developers to recover their annual fixed costs including a return on the capital investment.

In a perfectly competitive market with prices set by generator short-run marginal cost bidding alone, the resulting prices might be insufficient to cover the full costs of some of the plant on the system, in particular the fixed costs of marginal plant and the capital cost of new entrants. To ensure an adequate system margin, an additional sum of money is required above the revenue implied by generation-derived short-run marginal cost prices.

In a market where no new plant are required, the value of capacity has to be high enough to cover the fixed costs of existing plant that would otherwise close. In a market where new entry is required, the value of capacity has to be (expected to be) high enough to raise wholesale prices up to new entry levels – the price at which the most efficient new entrant would make returns sufficient to justify building the plant.

There are various means by which this additional 'value of capacity' is captured within competitive generation markets. Some markets (including the SEM) have explicit capacity or reliability mechanisms which reward capacity independently from energy. The GB market is an energy-only market in which the market price at times exceeds generation short run marginal costs. This does not imply anti-competitive behaviour, but instead reflects the economic theory that prices should include the risk that there is insufficient capacity to meet demand.

This mechanism requires that there should genuinely be (an expectation of) occasions with insufficient capacity to meet demand, and that prices are permitted to rise to very high levels (ultimately a value of lost load for consumers who are cut off) on these occasions. Peaking generators who run very rarely are not expected to capture the full revenue associated with the value of capacity. This is exacerbated by the 'pay-as-bid'

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[17] 'Variability of UK marine resources', Carbon Trust and Environmental Change Institute, July 2005

nature of the trading which raises risks that peaking generators would be unable to capture the full economic value of their output even if they were available to generate at times of extreme system stress. In practice some other sources of revenue are available in most markets which contribute to the fixed costs for certain plants, such as ancillary services contracts for reserve and other system services such as black start or frequency response.

The value of capacity is in theory related to the expected value of scarcity, and its existence can be explained in theoretical terms based on the 'value of lost load' (i.e. unserved energy) and the likelihood (as foreseen at the time of trading) that there will be insufficient capacity to meet demand (the 'loss of load probability'). The relationship is only approximate in the BETTA market, but can nevertheless be discerned, as the following analysis shows.

In terms of modelling, there are various alternative approaches to generate a value of capacity component in a market, including bidding up plant (raising their bids in the model to above short-run marginal cost) on an individual basis to recover their fixed (and possibly capital) costs. The difficulty with bidding up specific plant is that, as these plant retire and are replaced, it may be difficult to understand which plant can bid up to take their place. Another difficulty is that stations which operate at very low load factors (in a model) may need to set prices at very high levels during their limited period of operation, leading to a price profile that is unrepresentative of reality. Thus there is a risk of under recovery of costs. We believe that the value of capacity approach explained in the following section is consistent both with historical data and with the potential future development of the electricity system in a world with large volumes of renewable generation but we draw attention to the difficulty (including assumptions required) of making this framework internally consistent.

There are other means by which generators could capture the capacity value including the use of peaking generators to offer option contracts to other market participants. The present BETTA market is too illiquid (in short timescales) and with too much basis risk between the various trading, balancing and imbalance prices for these risk-management products to deliver secure returns to peaking generation, but in principle there is scope for further development.

2.5.1 Value of capacity in GB

The GB market has a single 'energy-only' market price, and observed wholesale market prices have systematically been higher than short-run marginal costs resulting from electricity market models. This difference can legitimately be attributed to a value of capacity element to prices.

The value of capacity tends to appear most at peak times of the day, and is greater in winter than in summer. This is illustrated in Figure 16 below, which shows the results of a 'backcast' of the Zephyr model, simulating hourly historical prices (SMP)[18] for 2006 and 2007. The blue lines show the SMP prices resulting from the Zephyr model, based on short-run marginal costs, whilst the orange lines show the out-turn market prices (derived from APX half-hourly prices inflated to match average prices reported by Heren for the day-ahead market).

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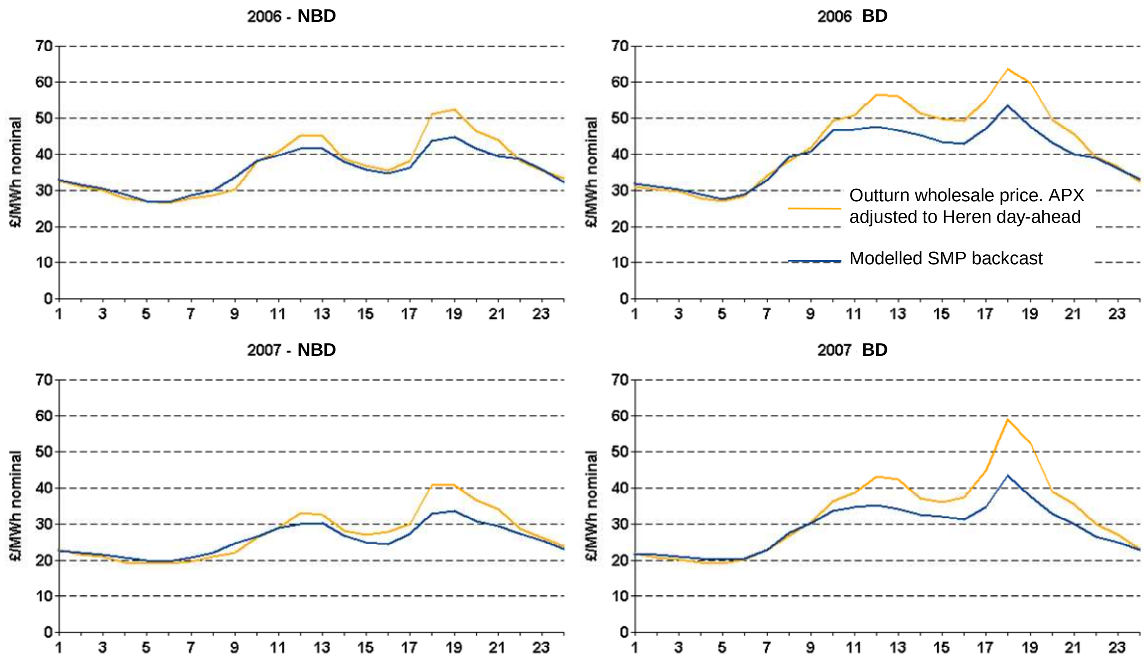
18 SMP is the System Marginal Price, representing fuel, carbon, start- and part loading costs, but excluding any Value of Capacity.

Overnight, there is a good match between the modelled SMP and actual prices. However, during the peak hours of the day, a gap opens between outturn prices and the modelled prices – the value of capacity. For example in 2006 business days (BD) at 6pm, the model SMP backcast was £52/MWh, whilst the out-turn price was over £60/MWh. In the market, the higher prices are caused by plant bidding above short-run marginal cost, in particular, mid-merit and peaking units as well as oil-fired units.[19]

Figure 16 – Comparison of model SMP and outturn market price



Source: Pöyry analysis; Heren and APX. BD is business day, NBD is non-business day.

By charting hourly data for three years of the inferred value of capacity against the system margin (the surplus of available generation over demand), as shown in Figure 17 below, an approximate relationship emerges. In 2006 and 2007, this relationship shows that when system margins are 30% or tighter, a gap appears between the SMP modelled price and the wholesale market price. When the system margin is 10%, the value of capacity is £10/MWh. The relationship holds in a similar pattern for both 2006 and 2007. The implied annual value of capacity, as shown in the table in Figure 17, is broadly consistent in 2006 and 2007, at around £4/MWh.

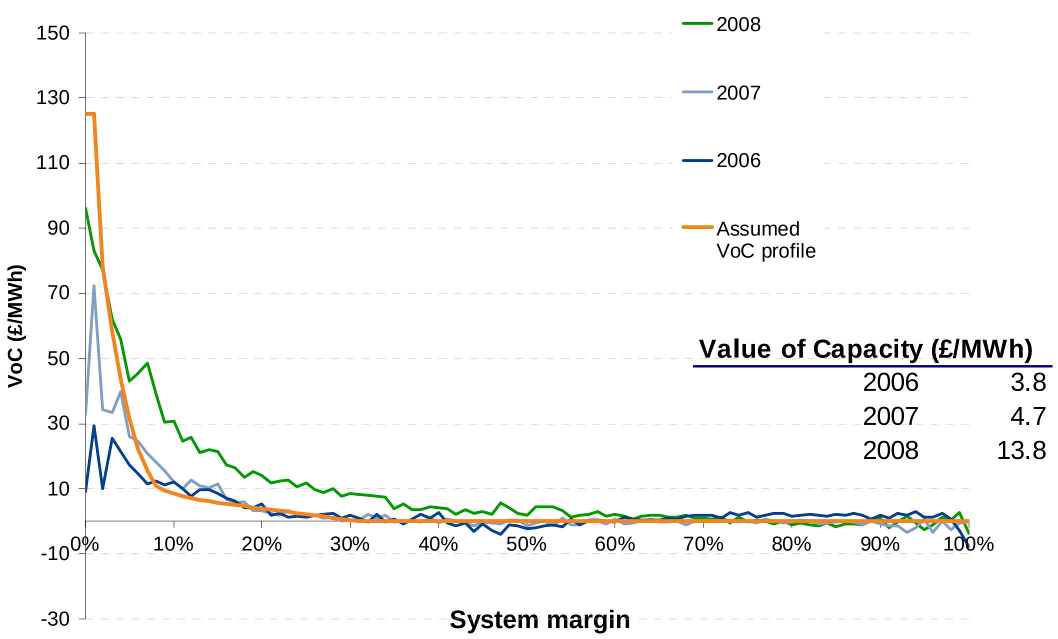
Hence for the modelling of future years, we have assumed a value of capacity profile – **before adjustment** – as shown in orange in Figure 17 based on a piecewise linear-exponential function.

For 2008, the relationship follows a somewhat different shape. A value of capacity appears when the System Margin is 60% or tighter, and the total value of capacity across the year is much higher. This appears due to a number of changes in the market in 2008:

19 It should be noted that bidding above short-run marginal costs in the GB market is permitted, whilst in Ireland it is not.

- **Opted out LCPD plant**. About 8GW of coal and 2GW of oil plant have opted out of the LCPD and hence have a maximum of 20,000 hours they can run between 2008 and 2015. As a result, these plant are not running until market prices rises well above their marginal cost of generation – they are now pricing at the opportunity cost of generation.
- **Delays to FGD fitting of LCPD plant.** A number of coal plant[20] incurred delays in fitting FGD. This meant that they were limited to an average of 2000 hours per year for the period until FGD was fitted.
- **Uniquely high commodity prices.** 2008 was a unique year in terms of commodity prices. Brent crude prices reached over $140/bbl, coal prices peaked at over $210/tonne and gas prices on the NBP soared to over 100p/therm for the Q1 2009 contract[21]. This led to a certain element of 'irrational exuberance' in many commodity markets, and this was reflected in the electricity prices as well.
- **North-south transmission constraints.** During the summer of 2008, there were significant transmission constraints between Scotland and England. This may have had an effect on generator bidding due to being constrained off.

Figure 17 – Historical relationship between the value of capacity (VoC) and System Margin



As a result of applying the assumed value of capacity profile to the SMP to create a backcast wholesale price, a much better fit between the model and outturn prices appears. This is shown for 2006 and 2007 in Figure 18.

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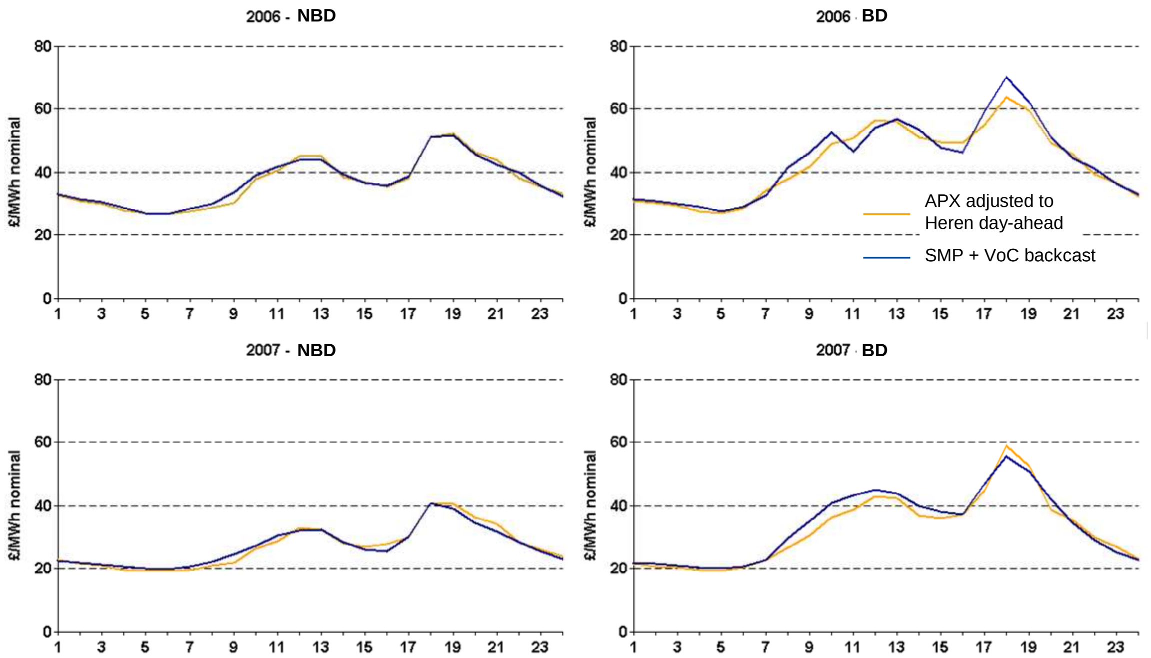
20 Aberthaw, Rugeley, Longannet, Fiddler's Ferry and Ferrybridge units 3 & 4.

21 Brent from EIA spot prices, coal McCloskey ARA CIF and gas Heren Q1 2009 contract for NBP.

Figure 18 – Comparison of model wholesale price (SMP + VoC) to market prices



In the past, the value of capacity component of prices has appeared at certain times of the day – especially peak hours between 5-7pm, and more during in winter than in summer. This reflects times of higher demand due to consumer usage patterns.

In a market with significant wind generation, the value of capacity may not appear at the times seen historically. Instead, it is likely to appear at times of system tightness, which could vary across the year with relatively short notice depending on how much wind generation there is at the time.

2.5.2 Value of capacity multiplier

Historically, the average value of capacity has not stayed constant, and has varied depending on the tightness of the generation system on an annual basis, as well as whether new entry is required. Thus into the future, it can be expected that the annual value of capacity will change depending on these factors.

However, in order to maintain a consistent level of security of supply as the amount of wind generation on the system increases, the system margin on average also needs to increase, with more periods of significant excess of capacity. Thus using our historically-inferred value of capacity relationship with system margin would result in a lower overall value of capacity, which would be below that required to cover fixed costs of existing plant. In turn if new generation is required, the value of capacity would be well below that required to incentivise new investment.

Thus to increase the value of capacity paid in GB, we apply a multiplier to the inferred relationship; i.e. the derived value of capacity relationship is multiplied up until the revenues for existing plant (or returns on new build plant) are consistent with them covering their fixed costs (or making the return on investment for new capacity). Note that for some very low-merit plants there is still a shortfall of revenue in our Core Scenario under existing assumptions.

In the Core scenario, the value of capacity component of prices varies over time, as shown in Table 2. In 2010 and 2015, the value is around £4/MWh, but this rises sharply in 2016 to almost £16/MWh, as the system tightens and is on the verge of new entry. However, with new renewables build and new nuclear the system becomes less tight and it drops back to £5/MWh in 2020 and 2025. In 2030, the value rises once more as new entry is needed.

To achieve this, the VoC multiplier rises from 6 in 2010, to 8.5 in 2016, up to 14 by 2030. Although the multiplier is identical in 2015 and 2016 at 8.5, the value of capacity rises from £3.7/MWh to £15.7/MWh as a result of the system becoming much tighter – more periods with a tight system margin lead to more periods of higher value of capacity.

Table 2 – Value of capacity and multiplier for Core scenario

	Multiplier	Value of Capacity £/MWh
2006	1.0	3.8
2007	1.0	4.7
2008	1.0	13.8
2010	6.0	4.5
2015	8.5	3.7
2016	8.5	15.7
2020	8.5	5.2
2025	10.3	6.5
2030	14.3	12.0

The importance of the value of capacity multiplier and the remaining revenue shortfall for peaking generation is discussed in more detail under the Core scenario in Section 0.

2.5.3 Capacity Payment Mechanism in the SEM

In the Single Electricity Market (SEM) in the RoI and Northern Ireland, a more explicit capacity payment mechanism (CPM) has been created as part of the market rules. At present the total annual sum paid by consumers to generators is based on the cost of a new entrant peaker in €/kW terms (net of ancillary service revenue and infra-marginal rent from operation in the energy market) multiplied by the kW required in the year to meet the all-island security standard. The annual payment is also split into monthly pots based on projected demand before the start of the year in question and further into half-hours based on a variety of forecast and outturn metrics intended to act as a proxy for the system margin.

The capacity payment is based on plant availability in any particular half hour rather than actual generation. This means that plants know for certain that they will earn a capacity payment when available (although not the actual price), even if they are not in merit and thus not generating.

2.6 Determining thermal new build (and forced closures)

This section refers to CCGTs, OCGTs and (in principle) coal plant. It does not apply to CCS coal, nuclear and additional CHP, which we have treated as non-market determined. The latter new entry, along with renewables, form the majority of the new entry.

We have assumed that any plant which are currently under construction, plus a few others which we believe to be very likely are commissioned, will be built irrespective of changes in the market in the next few years. These plant are listed in Section 4.2.3

2.6.1 GB market

After the specific projects described above have been commissioned, the overall volume of new build is determined such that there are not more than about two periods per year[22] (on average) with unserved energy. In a steady state (where plant commissioning and plant closures balance over an extended period and new entry profitability is in line with the levelised cost), we would aim for somewhat less than the 2 periods/year mentioned above. However, as most of the new entry is not market determined, a steady state does not result. (Of course, project developers in a competitive market will build plant if they think it is going to be profitable, not on the basis of a capacity margin *per se*. Yet there is a relationship between price levels and the capacity margin; and the margin we have assumed is consistent, in our modelling, with realistic returns for new projects.)

As our model does not cover all possible transmission constraints, and there could be unserved energy when the reserve or response provision is insufficient, Zephyr will tend to underestimate the amount of unserved energy there would be in practice. This is discussed in more detail in Section 6.8.1.

When new entry is required, we assume that plant with the highest return (from CCGT, OCGT and coal) are built. If more than one type of plant has high enough returns, we assume a mix of different plant are built. If no new entry plant are making the required IRR, we would need to increase the value of capacity (either by increasing the value of capacity multiplier, or, if possible, tightening the margin). If any of them are making well above the required IRR, we would reduce the value of capacity (either by loosening the margin, or reducing the multiplier). In all scenarios when new entry is required, CCGTs make the best rate of return with the exception of the Capacity Payment scenario.

In addition to the CCGT new entry described above, small quantities of coal and OCGT new entry are built so their rates of return can be assessed. These small additions have no material impact on prices or plant operation.

In many of the scenarios, some further OCGT capacity is built, in particular in 2030, despite the economics suggesting that CCGT would remain the only new build. There are a number of reasons for this:

- If only CCGTs are built, CCGTs will end up at the bottom of the merit order – this would result in less “infra-marginal rent[23]”, and a higher value of capacity would be required to ensure profitability. This is a particular issue in the IED scenario, where, with E class CCGTs closing, F class CCGTs which are not that much less efficient than the new entry CCGTs end up at the bottom of the merit order.

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[22] In the most extreme case, which is the IED scenario in 2020 this is relaxed to 3 periods per year.

[23] Contribution to fixed/capital costs due to having lower variable costs than the marginal plant.

- We have not considered evolution of ancillary service payments. With increasing wind reserve requirements, there will be significantly higher warming costs. If building OCGTs saved money (overall, taking their capital costs into account) by reducing plant warming costs this would be likely to happen although the exact mechanism is unclear.
- A small quantity of OCGT may in reality (this has not been modelled) be able to act as a price taker[24], without distorting the market too much.
- The analysis has only been taken until 2030 and not further until 2040 or 2050. If further renewables come onto the system post-2030, and this is clear that it will happen in 2030, it may be economically justified to build OCGT rather than CCGT. Since this study has not looked beyond 2030, it is not possible to comment on how the system might evolve after 2030.

With just a small quantity of OCGTs, and inelastic demand, it is possible that the OCGTs could contract to only run at extremely high prices. However, while this may lead to less value of capacity at other times, overall it would probably lead to higher prices. If this did occur more OCGTs would be built, but once they started competing with each other prices in hours when they run would fall. There would then be little OCGT investment, until capacity margins became tight again, so a cyclical investment cycle may result.

If our non-market determined capacity results in an overcapacity, we close plant which are not (approximately[25]) recovering their fixed cost. This results in a higher value of capacity (although it will still be lower than in years where new entry is required). This is done until the plant does recover their fixed costs or we start getting significant unserved energy. Plant closures are a particular issue for E class CCGTs[26]. On the whole, once we have closed plant, the remaining E class CCGTs do roughly recover their fixed costs. In reality some of the CCGTs may be mothballed rather than closed down. However, when we close the CCGTs (e.g. 2019) some only have about 8 years of their lifetime remaining, so are more likely to close down than be mothballed, as we do not have a need for new entry until near 2030.

2.6.2 SEM (Single Electricity Market)

As there is a capacity payment in the SEM the situation with regard to new entry is somewhat different than in GB. We have assumed a fixed value of capacity (both in terms of the within year profile, and the annual average). In the case of OCGTs, this assumption does mean there is little relationship between capacity margins and the profitability of new entry[27]. However, we have built sufficient new entry to keep a reasonable capacity margin. The assumption is that if the capacity margin got too big, there would not be any new entry, as companies would be unwilling to take the risk of the capacity payment falling. For OCGTs, we have also assumed the ancillary services payment remains constant.

A difficult issue is exactly what constitutes a tight margin, given that SEM has (by 2015) 1.4GW of interconnection with GB, which is over 20% of SEM peak demand. We have assumed that CER/NIEUR set the capacity payment so that SEM does not become over-

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24 Run whenever the price exceeds its marginal costs.

25 In the case of CCGTs we have not considered any non-energy market revenue. In reality some non-energy market revenues is likely for very low load factor CCGTs.

26 The assumption is that CCGTs will need to recover most of their fixed costs through the energy market.

27 Almost all OCGT revenues come from the capacity payment.

reliant on GB. For this reason, there is no unserved energy in SEM in our scenarios[28]. In 2030, when the capacity margin is tight in GB, it is quite large in SEM, as from 2025-30 a 450MW CCS coal plant has been commissioned, along with more renewables and few plant closures.

In deciding what to build the (market-determined) new entry in SEM is a mix of CCGTs and OCGTs. CCGTs are only built if they would be profitable (at least comparable to an OCGT)[29]. If CCGTs were significantly more profitable than OCGTs, they would form the vast majority of the new build.

[28] For this to be the case SEM may need to import at times when the GB wholesale price is more than the current maximum SEM price of €1000/MWh. This is allowed in our model.

[29] As in GB, a very small volume of new entry may be built to assess IRRs.

3. WIND AND WIND GENERATION IN GB AND THE SEM

To understand the implications of intermittency, we have undertaken research into the patterns of wind and wind generation historically and how these will influence the future. This section highlights the methodology and data that has been used to generate future profiles of wind generation in GB and the SEM, and examines how accurate the resulting model is for the SEM in 2007. We also then answer a series of questions on the wind and wind generation including correlation of the wind, and the relationship between wind and demand.

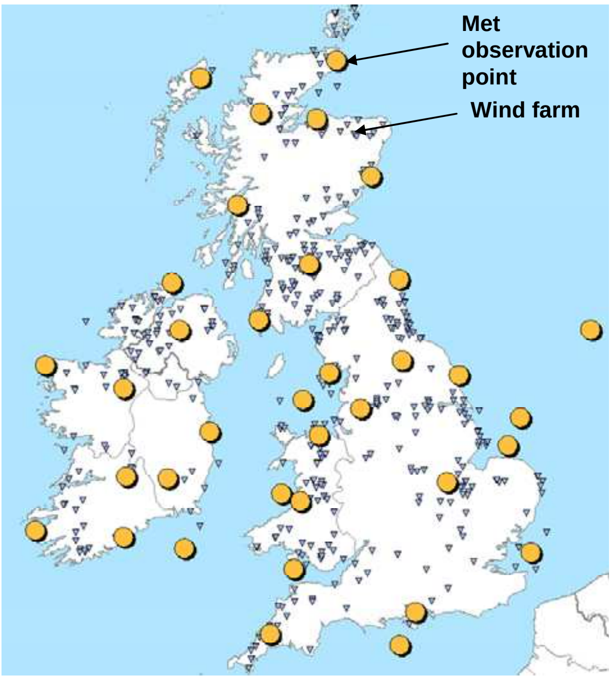
3.1 Overview of data and methodology

3.1.1 Wind speed data

To create the most realistic generation profiles possible, historical hourly wind speed data was purchased for 2000-2007 for 36 locations covering the UK and the ROI: 10 covering onshore and offshore locations for the SEM and 26 covering GB onshore and offshore locations. The choice of wind locations is the result of collaboration between ourselves, the intermittency project Founders and the Met Office. Areas of interest were defined for onshore and offshore sites based on current locations of wind farms and expected future locations,

Given these areas, the Met Office and Met Éireann advised on which synoptic stations were most representative of the areas in question. As a result, the distribution of actual and expected installed capacity has influenced the selection of wind sites. Figure 19 presents the final selection of wind locations in relation to planned and operational wind farms.

Figure 19 – Location of selected observation / NWP stations for GB



The hourly wind speed data covers GB and SEM markets for the period 2000-2007. The reason for the selecting these years is a consequence of poor data availability in earlier years which would have lengthened the data acquisition and processing time unnecessarily.

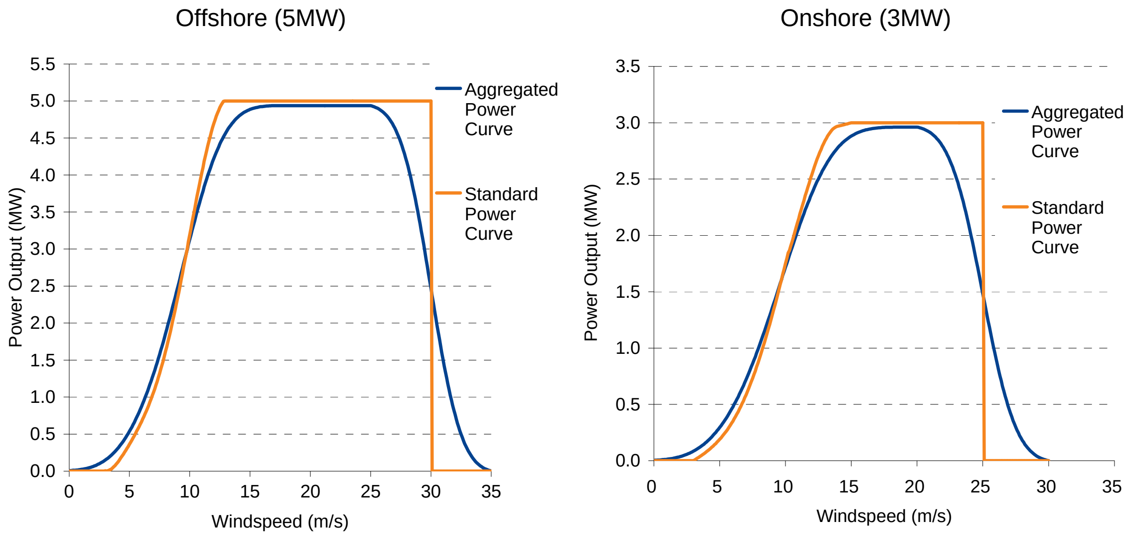
Offshore data for GB was derived by a numerical weather prediction program (NWP). Such programs take data from weather buoys surrounding the chosen location and output hourly wind speed data for a given location.

3.1.2 Conversion of wind speed data to wind generation

This is an overview of the methodology used – for a more comprehensive description, see the Appendices.

Since the speed data is from meteorological masts at 10m height, the hourly wind speed data was adjusted to reflect the difference in height between the mast and hub height of a wind turbine (around 80m high). The uplifted wind speed was converted to a power output from a wind turbine using a power curve, as shown in Figure 20. These represent the power output of a wind turbine for a given wind speed. At low wind speeds below the cut-in threshold, the power output is zero. Above about 4m/s, it rises quickly (with the cube of the wind speed), and flattens of as the wind turbine caps power output (usually by changing the angle of the blades). Above a certain wind speed (25m/s onshore, 30m/s offshore) the wind turbine cuts out completely and stops generating to prevent damage to components. The standard power curves for a turbine (shown in orange in Figure 20) have been converted to represent the output for a group of turbines – the ‘aggregated power curve’. In particular, a group of wind turbines together will have a smoother output than a single turbine, and will not all cut out together at high wind speeds, due to the variation from gusts of wind across a site.

Figure 20 – Standard and aggregated power curves



3.1.3 *Installed capacity scenario*

Current installed capacity covering the GB and SEM markets was taken from our internal sources and the British Wind Energy Association.

As the model timescale extends to 2030, it has been necessary to formulate scenarios that are consistent with the expectation of a high degree of installed wind capacity assumed in this study. Reports from industry and government have guided the creation of the installed wind capacity scenario. For the SEM, the Grid 25 report has been used as a key reference. The scenario for GB has been informed by sources including UK government targets and the offshore licensing rounds of the SEA and Crown Estate. This study has not assessed the economics of wind generation, and the ratio of onshore/offshore wind is an input to the study from that an output from it. Equally, we have not examined in detail the geographical constraints that may limit wind development, such as areas of outstanding natural beauty or national parks.

Figure 21 shows the installed capacity in each market compared to peak demand. Despite the greater amount of installed capacity in GB, the SEM has higher wind capacity as a proportion of demand. In addition, the distribution of installed capacity varies between the two markets: the UK has greater proportion of offshore capacity (expressed as a ratio of total installed capacity) than the SEM. The implications of this are covered in subsequent sections. Figure 22 shows the geographic location of the installed wind capacity.

Both scenarios involve high installation rates of wind capacity. The rate of installation in both markets is not constant but increases to 2020 before reducing to 2030. Such a dynamic could have significant implications for the wind generator supply chain that are not explored further in this study. In addition, the UK sees significant expansion in offshore wind post-2015 while the onshore wind development is curtailed. In the SEM, onshore wind resources continue to be developed to 2020 before a significant increase in offshore capacity takes place between 2020 and 2030.

Figure 21 – Installed capacity in GB and SEM

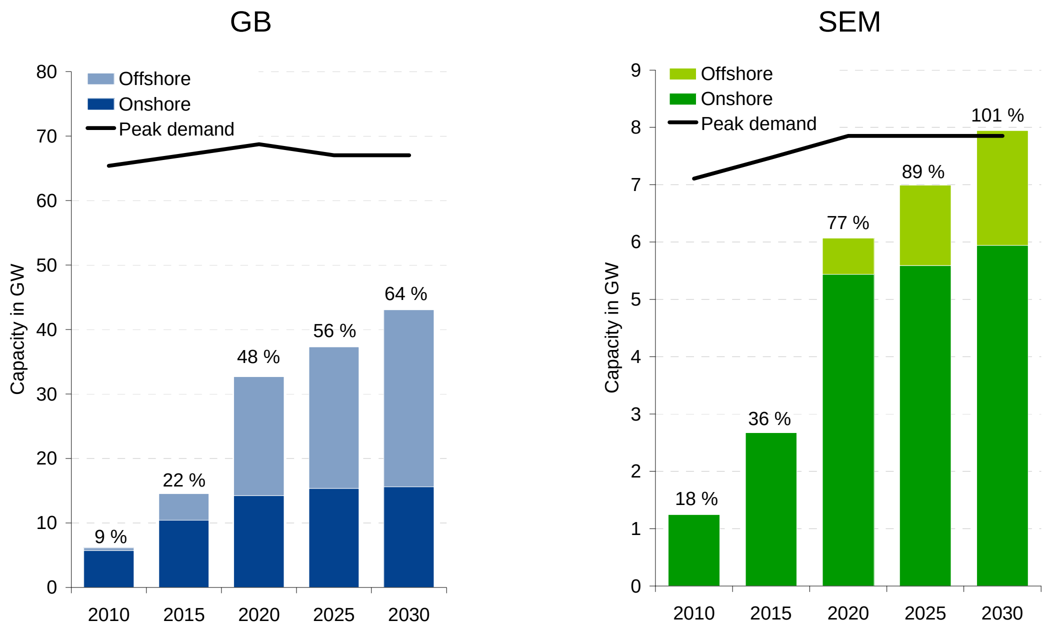
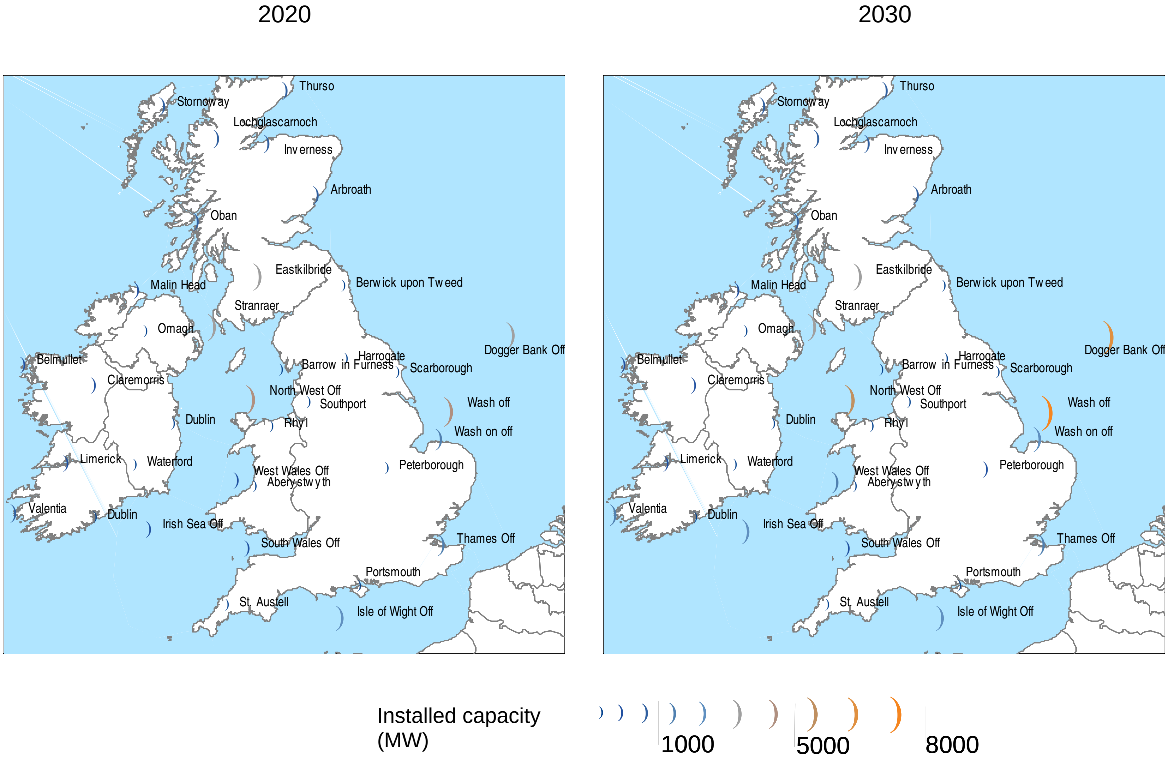


Figure 22 – Location of installed capacity in GB and SEM in 2020 and 2030



2020		2030	
GB Capacity:	32.7GW	GB Capacity:	43.1GW
SEM Capacity:	6.1GW	SEM Capacity:	7.9GW

3.1.4 *Model validation*

The objective of model validation is two fold: firstly to ensure that the hourly generation profile produced by the wind model is realistic, and secondly to derive regional adjustment factors so that the total energy generation from wind for the GB and SEM markets are consistent with recorded data. Historical wind speed data is used in conjunction with adjusted historical demand data to ensure consistency between datasets when scenarios are run in the electricity model Zephyr.

Model validation has been conducted using hourly generation data from EirGrid for the SEM, and monthly generation data from the ROC mechanism. As a result, the wind model data, based on wind locations, has been aggregated to the appropriate level in order enable a comparison with the validation data.

Figure 23 shows a back cast of the wind model output compared to hourly wind generation data for the SEM for an illustrative period with significant variation in wind output. This demonstrates that the wind model matches observed wind output with a high degree of accuracy.

Figure 23 – Comparison between model and actual generation data for SEM

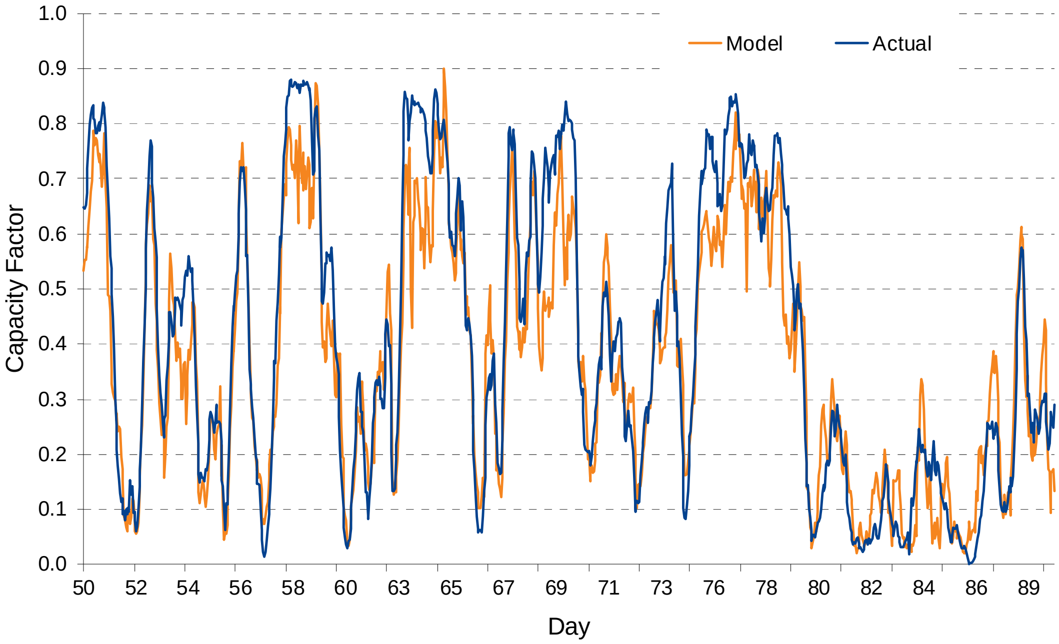
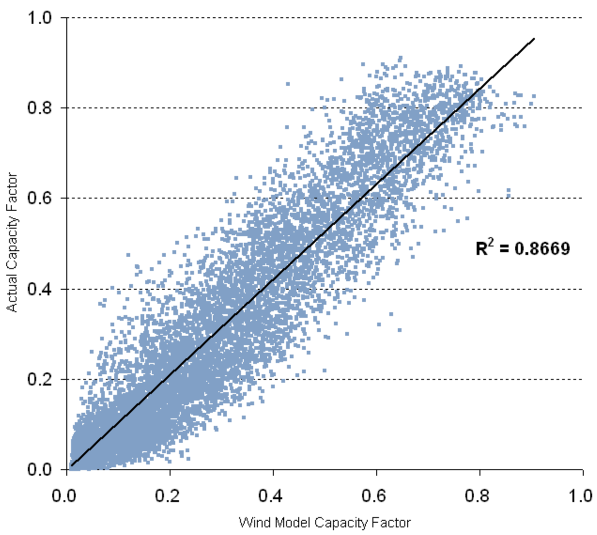


Figure 24 presents the correlation between the wind model data and the EirGrid wind output data, and confirms that the model is in good agreement with the recorded generation data.

Figure 24 – Correlation between wind model and EirGrid data



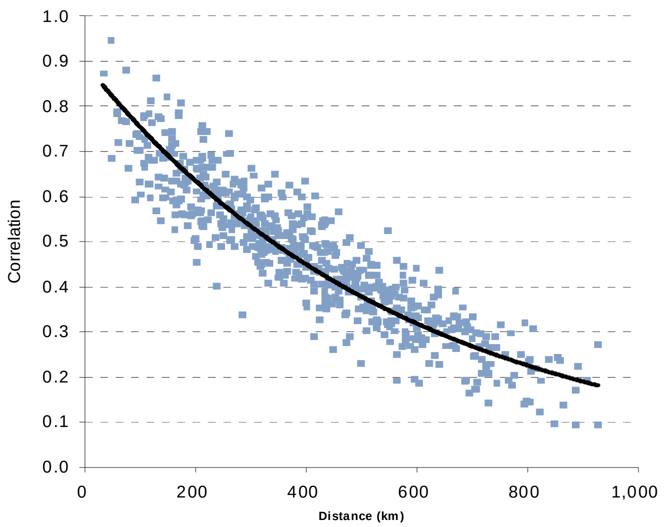
3.2 Wind correlation

In general, the variation in wind speed between wind locations at any given time has a beneficial effect on the output profile for the whole wind generation system, smoothing out, to a limited extent, peaks and troughs and thereby leading to a less peaky wind generation profile. This section investigates the degree to which wind speed and hence power output is correlated between wind locations in the GB and SEM markets

3.2.1 How correlated is wind speed between locations?

Figure 25 shows the correlation of wind speed at wind locations with respect to distance between the locations. The calculation covers all 36 wind locations for the 8 Monte Carlo years resulting in 630 points being plotted. At a distance of about 200km apart (roughly London to Birmingham) there is a correlation of around 0.65 between points, whilst by 900km apart (approx London to Aberdeen) the correlation drops to 0.2.

Figure 25 – Correlation of wind speed over distance



Note: Correlation measured as r^2 value

It should be noted that the wind locations in this study have not been chosen as being representative of the entirety of UK and Ireland but rather for coverage of areas where a high amount of installed wind capacity is expected. Therefore it is to be expected that the average correlation of wind speeds will be slightly higher for the sites used in this study rather than the studies where sites were chosen for geographical coverage.

In general it can be concluded that with increased distance between sites, the correlation of wind speed between the sites decreases. This confirms the expectation that low periods of wind at one location can be to some extent be offset by high wind speeds at a different location. The effect of this is to reduce the variability of wind generation.

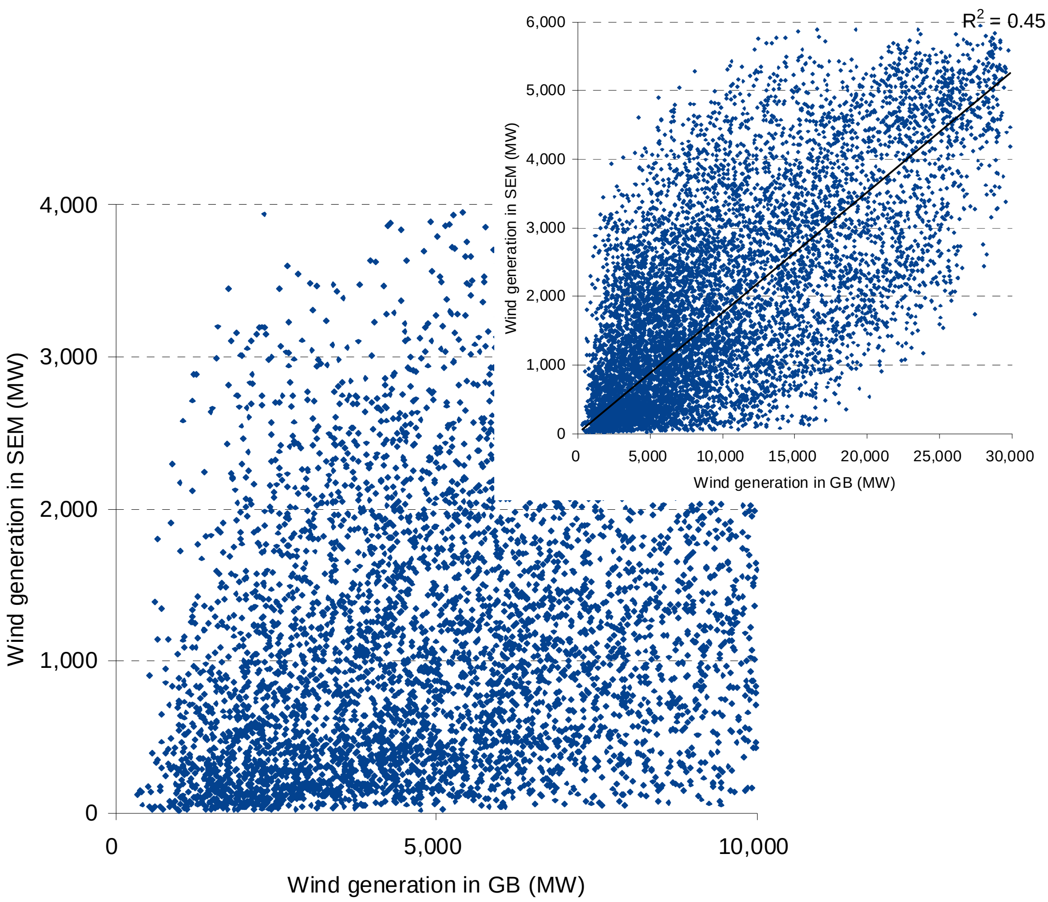
In terms of application at the market level, this analysis implies that there is likely to be more correlation between wind speeds, and hence power output in a geographically small area than a large area. Therefore one would expect that power output between sites in the SEM is on average more correlated than that in the GB market. Obviously, this does not take into account weighting caused by the amount of installed capacity in on location e.g. an offshore site such as Dogger Bank. The implications of both of these points are addressed in subsequent sections.

3.2.2 How correlated is wind generation between the SEM and GB markets?

A high degree of correlation between wind generation in the SEM and GB could impact the value of interconnector installations between the respective markets.

Figure 26 shows the correlation of power output between the GB and SEM markets.

Figure 26 – Correlation of wind generation in GB and SEM in 2020



A relationship does exist between the two markets albeit not a strong one – it is clear that there are no times of high wind generation in GB and low wind generation in the SEM and vice versa. Equally, there are many periods when wind generation output in the two markets is similar and correlated. However, the relatively low level of the correlation at 0.44 implies that there will be opportunities where lower wind generation in one market may be countered by higher wind generation in an alternative market thereby creating an opportunity to sell excess wind generation.

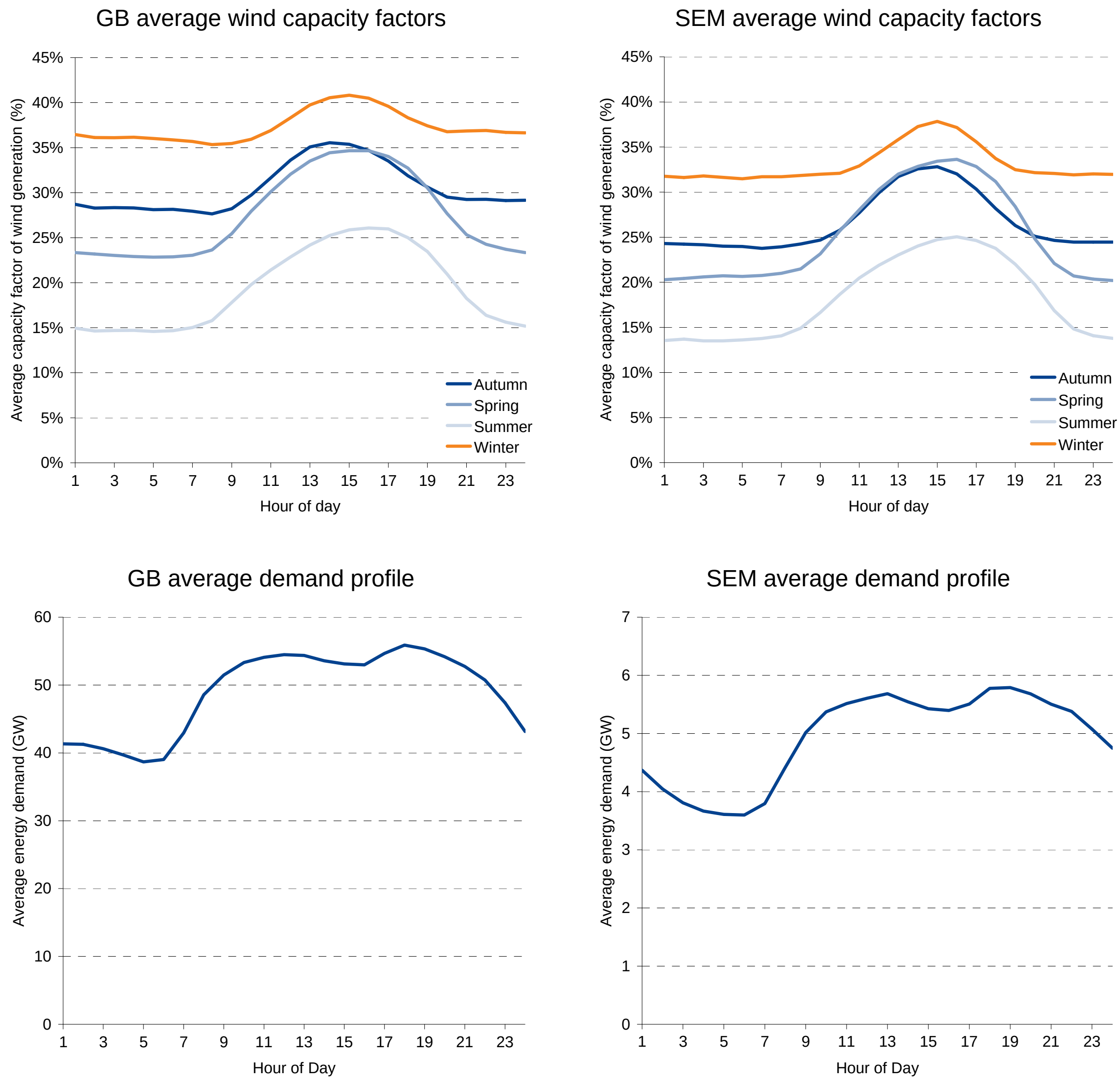
3.2.3 How correlated is wind and demand?

Correlation between energy generated from wind and demand could reduce the requirement for extra generation capacity, particularly if peak wind generation coincides reliably with peak demand. Although there is a relationship between wind and demand, it is weak.

Figure 27 shows the average capacity factor per hour of the day for the GB and SEM markets for each season, along with the average demand profile. The capacity factors have been derived from all Monte Carlo years and all wind locations and therefore represent an average of the data set.

There is variation in wind capacity factors across the day, with a low period of wind generation overnight followed by an increase in the mid afternoon before dropping off to the overnight level. Peak wind generation (usually occurring at approximately 3pm) broadly coincides with peak demand (at 6pm). There is significant variation in average capacity factor between seasons, with more consistent wind speed regimes expected in winter compared to summer (a difference of 10% in summer compared to 5 or 6% in winter). In addition, the period of peak generation moves between seasons, with autumn and winter exhibiting peaks at earlier times of the afternoon, while spring and summer periods exhibit peaks in capacity factor later in the afternoon.

Figure 27 – Average capacity factors per hour and season for GB and SEM

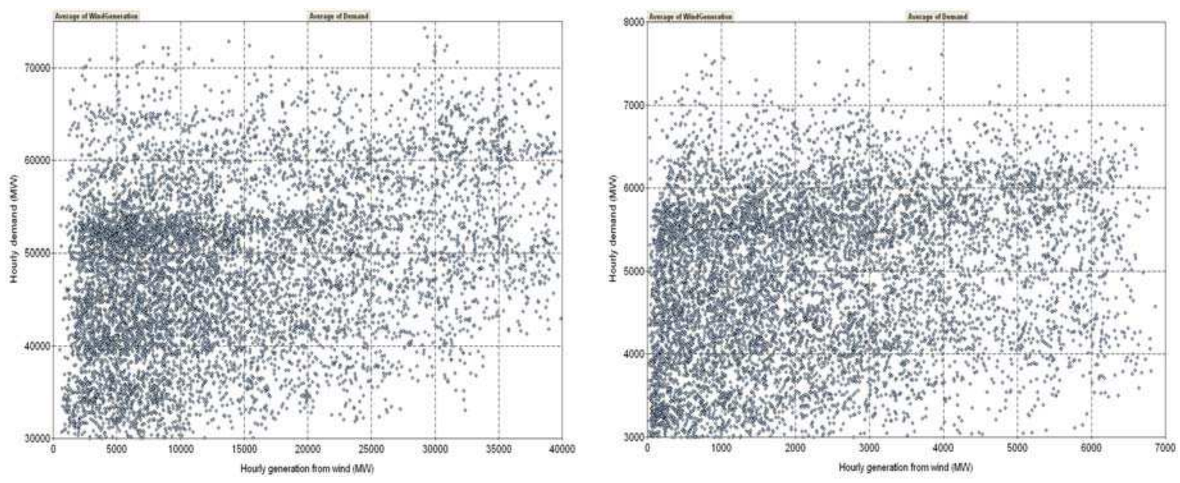


It should be emphasised that these represent averages, and there is considerable variation around them – in particular for the wind.

Figure 28 – Correlation between wind and demand for GB and SEM

GB – Monte Carlo year 2002 in 2030
r squared = 0.10

SEM – Monte Carlo year 2002 in 2030
r squared = 0.05



Although there are trends between wind and demand, it is not a strong relationship and masked by the significant variation in the wind. Figure 28 illustrates the correlation between hourly generation from wind and demand for Monte Carlo year 2002 in 2030. It can be seen that the correlation between wind and demand is poor. This result implies that wind generation cannot be expected to always be available when required.

3.2.4 How often are there 'no wind' events?

A no wind event is defined as a period when there is no power output from a wind location. Given the shape of the non aggregated power curve (Figure 20), both low and high wind speeds can lead to no power output. It is therefore important to identify both the number of low and high wind speed periods that lead to no generation.

The aggregated power curve, Figure 20, shows that the cut in and cut out speeds for a number of turbines over a given area is not the same as that for a single turbine. Table 3 reports the number of periods where high wind speeds (over 30 and 35 m/s) and low wind speeds (less than 1m/s) occur. The total sample size is 2.9 million data points covering all Monte Carlo years under investigation and covers all wind locations. It can be seen that in relation to the sample size, there are relatively few low wind periods. Moreover, a low wind period is only defined for one location. In reality, the system sees generation as the product of multiple wind locations. As a result the impact on the overall system depends on the amount of installed capacity at the particular location where a low or high wind speed event occurs.

Table 3 – Count of low and high wind speed periods

Wind speed	Count of periods
<1 m/s	131,844
<5 m/s	1,098,309
>30 m/s	284
>35 m/s	52
Total sample size	2,865,024

Table 3 shows that the majority of no wind periods are those in which the wind speed is less than 1m/s, while outages due to high wind speeds are far less common. This finding coincides with the properties of the wind speed distribution (Weibull distribution[30]) that shows a relatively large number of low wind speed events and a small number of very high wind speed events.

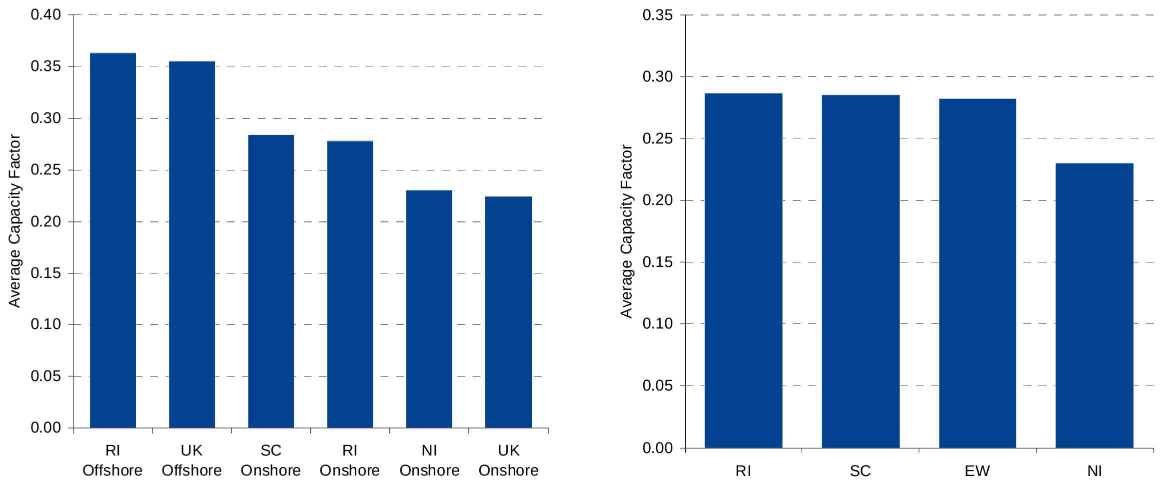
In conclusion, there are relatively few ‘no wind’ events. Moreover, given a ‘no wind’ event, the likelihood is that the cause is low wind speed rather than high wind speed. This is in line with expectations given that wind speeds in Northern Europe conform to a Weibull distribution.

3.3 Variation in wind

3.3.1 How much does generation vary by differing locations?

The amount of energy from wind varies from location to location and is dependent on the wind conditions and the installed capacity at individual locations. Figure 29 presents the average capacity factor derived from capacity factors for individual wind locations, scaled up to the country level. The derived capacity factors are not weighted by installed capacity; therefore the actual capacity factor of wind for the GB or SEM markets will be defined by the level of installed capacity per wind location.

Figure 29 – Capacity factors per region



Note: RI is Republic of Ireland, SC is Scotland, NI is Northern Ireland.

As a rule, it appears that offshore sites exhibit higher capacity factors in general than onshore sites. Due to the large amount of installed capacity offshore, it is to be expected that offshore sites will in effect ‘pull up’ the average capacity factor for the respective markets. In terms of onshore sites, the Scottish and RoI locations exhibit higher capacity factors in general due to higher average wind speeds, while the wind locations in England and Wales are of lower generation.

30 A Weibull distribution is a continuous probability distribution with a skew, with a higher probability of low values than high values. It is frequently used to represent wind speeds.

3.3.2 How much does wind generation vary between years?

The previous sections highlighted the aggregated profile of wind capacity factors; the amount of installed capacity alters the observed capacity factor by weighting areas with high installed capacity more than those with low installed capacity. This section analyses the effect and characteristics of large scale wind generation in GB and SEM markets under the standard scenario. Areas covered include the amount of energy produced from wind and its associated profile and the identification of low and high wind energy production periods.

Table 4 shows the sum of wind generation for the eight Monte Carlo years for 2020 and 2030 in our Core scenario for GB. In 2020, wind generation varies between 83.2TWh and 93.3TWh, a range of 10TWh or 12%. In 2030, with greater installed wind capacity, the variation is 15TWh or 13%. The slightly greater variation in 2030 despite identical underlying wind speed data is due to changes in the location of installed capacity.

In the SEM in Table 5, wind generation in 2020 varies between 14.6TWh and 17.7TWh in 2020 – a change of 3.1TWh or 21%.In 2030, the variation is 4.5TWh or 24%. The reason for the greater variation in the SEM is due to the market being geographically smaller than GB, and hence experiences a higher correlation in wind than GB.

Table 4 – Wind generation in GB for 2020 and 2030

GB – 2020			GB – 2030		
MC Year	Annual wind generation (TWh)	As % of annual demand	MC Year	Annual wind generation (TWh)	As % of annual demand
2000	92.1	24%	2000	125.7	34%
2001	83.5	22%	2001	113.4	30%
2002	89.6	23%	2002	121.4	32%
2003	83.2	21%	2003	112.3	29%
2004	88.5	23%	2004	120.3	31%
2005	90.8	23%	2005	123.9	32%
2006	89.3	23%	2006	121.3	32%
2007	93.3	24%	2007	127.3	33%

Table 5 – Wind generation in SEM in 2020 and 2030

	SEM – 2020			SEM – 2030	
MC Year	Annual wind generation (TWh)	As % of annual demand	MC Year	Annual wind generation (TWh)	As % of annual demand
2000	17.7	41%	2000	23.3	54%
2001	14.6	33%	2001	19.0	43%
2002	17.4	40%	2002	22.6	52%
2003	16.3	37%	2003	21.4	49%
2004	17.4	40%	2004	23.5	54%
2005	16.2	37%	2005	22.3	50%
2006	16.8	37%	2006	23.1	52%
2007	15.7	35%	2007	21.7	49%

3.3.3 *How does wind generation vary during the year?*

Figure 30 represents the load duration curve for energy from wind for the GB market in 2020 and 2030. The diagram plots the cumulative probability of the energy generated from wind as being below a certain value, hence hourly generation from wind farms in the UK market in 2020 is below 30GW for 100% of the time, and below 10GW for 60% of the time. The installed capacity in 2020 and 2030 is 32.7GW and 43GW respectively.

Figure 30 – Cumulative wind duration curve for GB in 2020 and 2030

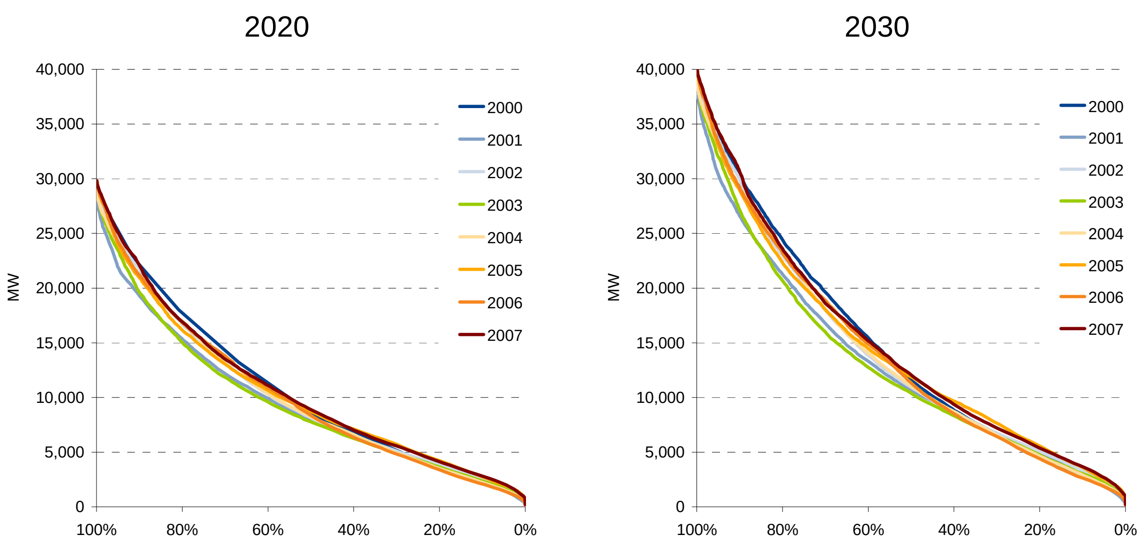


Chart shows cumulative probability of the energy generated from wind as being below a certain value.

Figure 31 shows the duration curve for the SEM market. The main difference between 2020 and 2030 relates to the amount of installed capacity for each market. Although the wind duration curve shows the proportion and amount of energy generated from wind over a year, information regarding hourly variations in energy output from wind capacity is obscured.

Figure 31 – Wind duration curve for SEM in 2020 and 2030

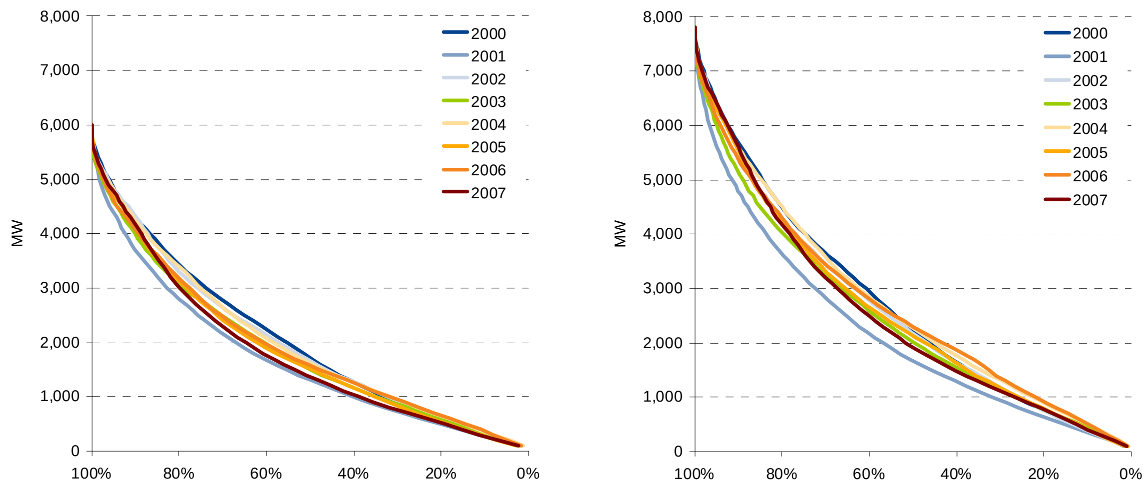


Figure 32 is illustrates the difference in system load factor that occurs as the balance of capacity shifts from onshore to offshore in the GB market. The curves have been produced from referencing Monte Carlo year 2002, then dividing the hourly output by the total installed capacity to obtain an hourly capacity factor for wind generation in GB and SEM. Plotting the capacity factor in the form of a duration curve allows the effect of increased offshore wind installation to be observed.

Figure 32 – Capacity factor duration curve for SEM and GB

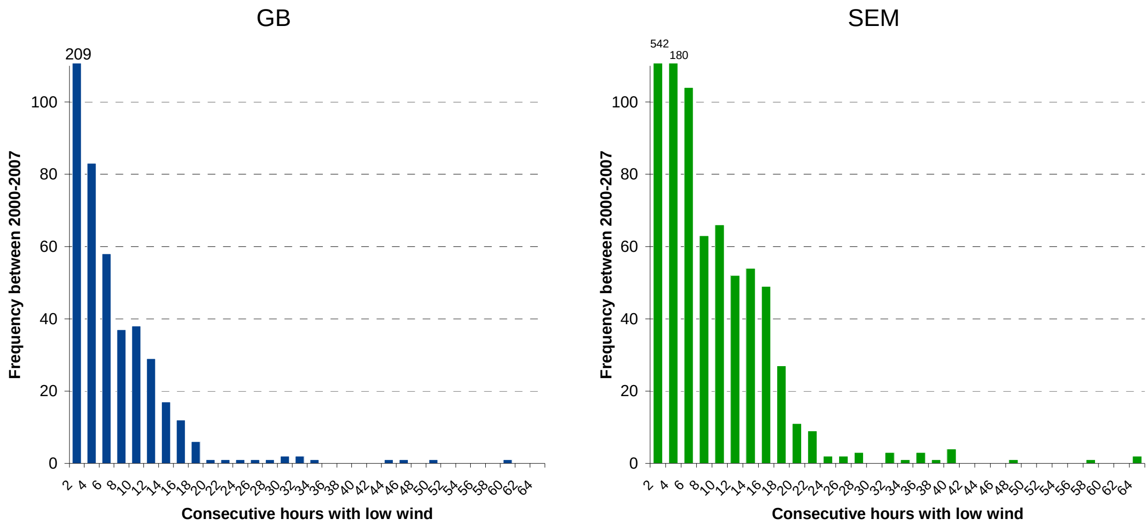
The influence of offshore wind, with a higher average capacity factor (see Figure 29) on the average capacity factor in the UK can be seen in the left hand curve of Figure 32; the curves for 2020 and 2030 split at 50% with the 2030 curve displaying a higher capacity factor for the remaining hours. By comparison, the curve for the SEM shows a barely discernable difference – as a result the difference is due to the split between installed capacity offshore and onshore.

3.3.4 How often do periods of low and high wind generation occur, and how long do they last?

Low and high wind generation periods are defined as being periods in which generation from wind contributes less than 5% of maximum wind output or more than 95% of wind output. These periods are of interest as they define the number and duration of times in which the system experiences a shortfall or abundance of wind generation. Both events have implications for the electricity system in terms of capacity requirement and prices. This section investigates the number of low and high wind energy periods in order to characterise the likelihood and frequency of these events on the system.

3.3.4.1 Low and high wind energy periods

Figure 33 – Count of low wind energy periods – GB and SEM 2020



Analysis covers 8 years of data (70,080 data points for each market). Each band represents a two-hour period

Figure 33 plots the frequency of occurrence of low wind periods against the length of time they occur for, in the UK and SEM markets. As would be expected, the distribution is skewed towards wind periods with short durations – as the length of time increases, so the frequency of occurrence decreases. For the purposes of this study, such periods are interesting as they represent the periods when the generation system is under significant stress, as obvious sources of flexibility such as pumped storage cannot operate at full capacity for more than 5 hours.

The distribution of low wind periods varies between the GB and SEM markets, mainly due to geographical coverage. For example, in the GB market there is one period in the 8 Monte Carlo years where wind generation is less than 5% of demand for nearly 3 days.

There appear to be more periods in the SEM over 24 hours – this is due to the relatively low geographical spread in the SEM. In addition, there is one continuous period in the SEM when the amount of generation is continuously low for a period of 64 hours.

The distribution of high wind energy periods is presented in Figure 34 and Figure 35 for the GB and SEM markets. These are periods when wind generation could account for more than 95% of generation on the system, not being subject to any constraints

Figure 34 – Count of high wind energy periods – GB

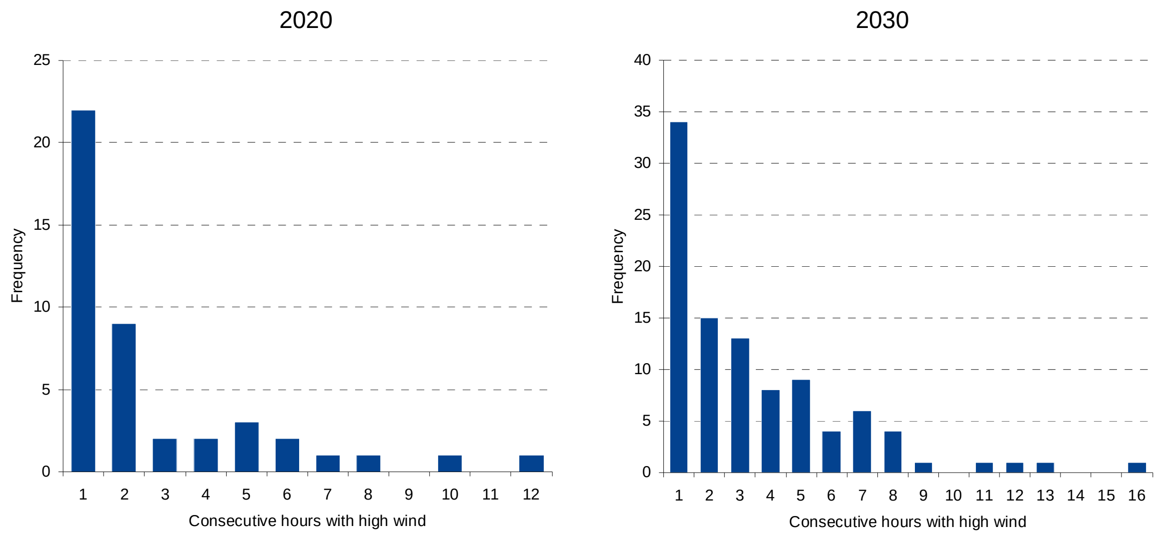
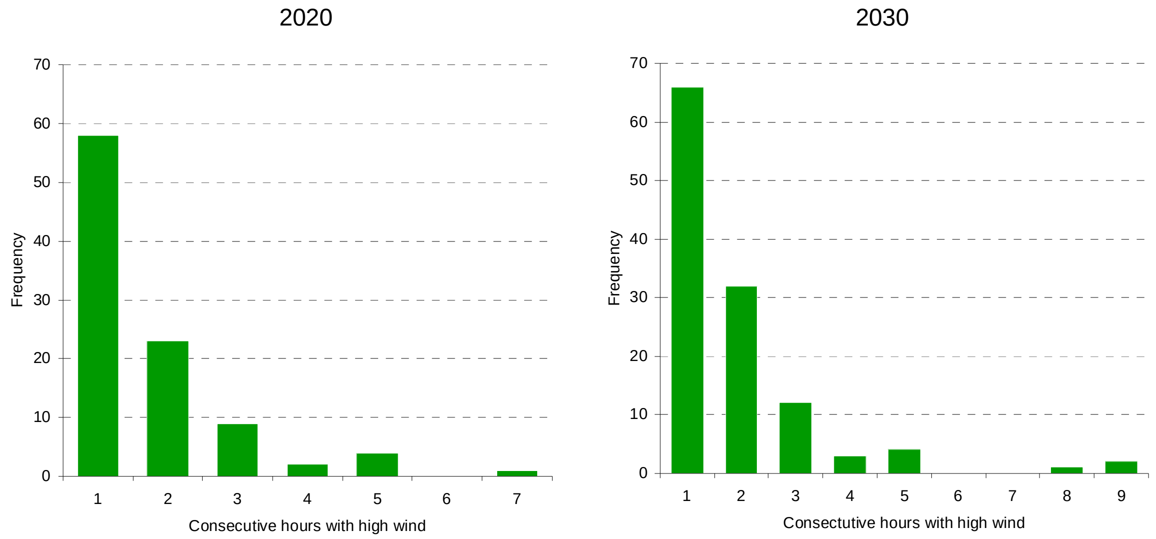


Figure 35 – Count of high wind energy periods SEM



As in the low wind energy case, the distribution of high wind periods is skewed towards shorter duration instances, with the maximum duration being 9 hours in the SEM and 16 hours in GB in 2030, and 7 hours in the SEM and 12 hours in GB in 2020. However, the number of high wind energy periods also increases in both markets between 2020 and 2030 – GB has 118 high wind energy hours in 2020, but 339 hours in 2030. The SEM also sees the number of high wind energy periods increase from 166 hours to 224 hours. The reason for this difference is the increased installed capacity offshore. As a result, the average capacity factor would be expected to increase, as the amount of installed capacity has the effect of weighting the higher capacity factor more, hence pushing up the overall capacity factor.

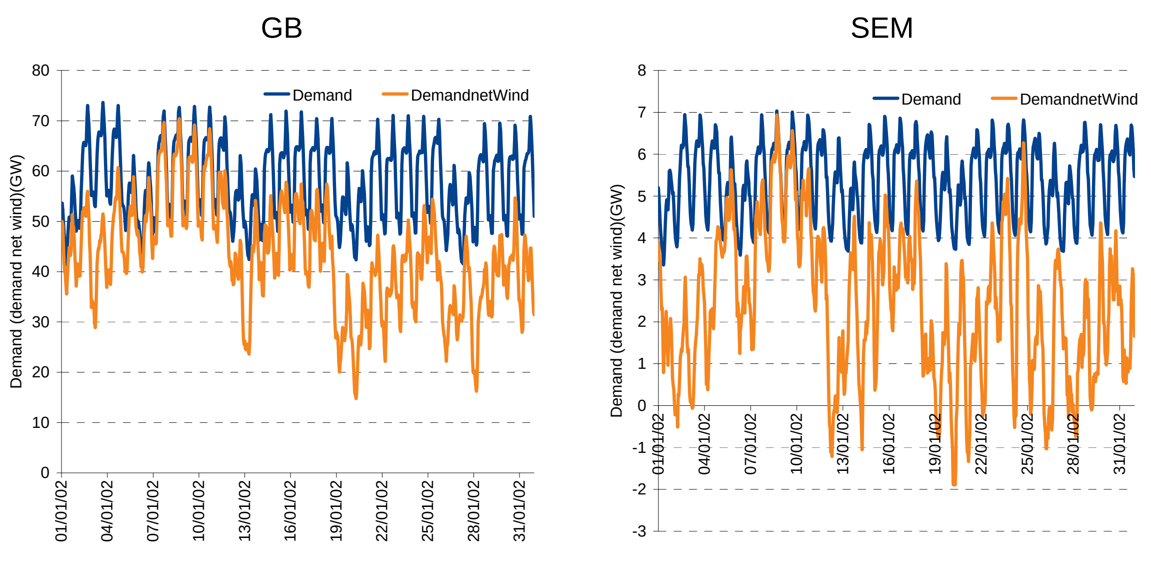
3.4 Wind and demand

This section addresses wind and demand and in particular, the modified demand profile that is exhibited by the GB and SEM systems as a result of the significant amount of installed wind capacity.

3.4.1 What does demand look like after wind?

Since wind is generally a price taker and runs ahead of all other generation, demand net of wind is what the rest of the thermal system will have to meet. The fluctuating nature of wind generation means that the resulting demand profile net wind is very different to that of the underlying demand profile. Variations in demand net wind are significant and unpredictable. Figure 36 shows the effect of wind on demand profile for January in 2020. It can be seen that the effect of wind is to alter the regular nature of the standard demand profile and replace it with a highly variable modified demand profile. The extent of the modified profile is a function of the installed capacity of wind on the system.

Figure 36 – Hourly demand net wind profile for GB and SEM in January 2020

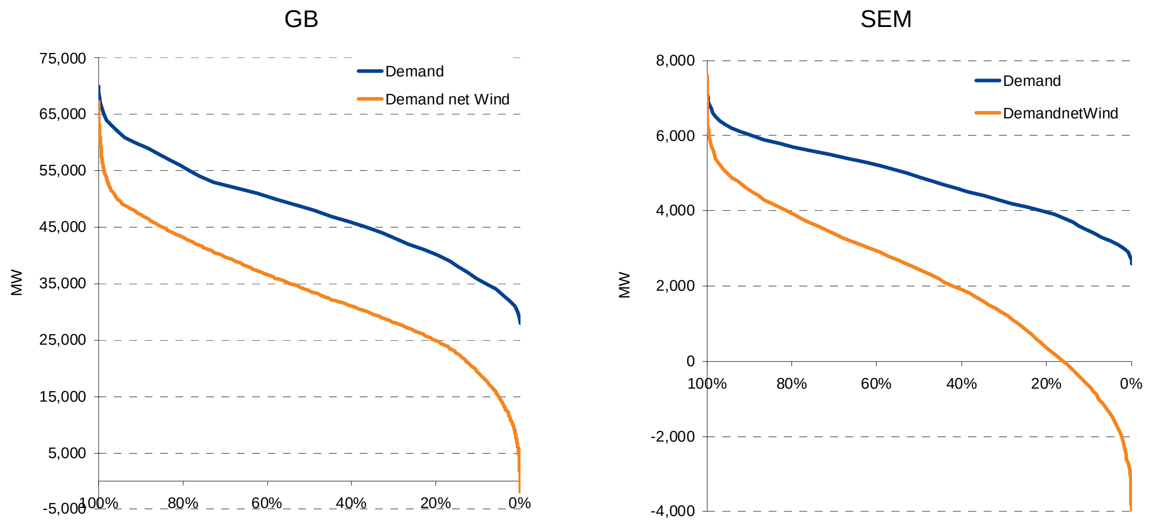


Data from January 2002 Monte Carlo.

The demand duration curves with and without the effect of wind energy for the SEM and GB markets are shown in Figure 37. The curve plots demand as a function of the proportion of the year that demand is above or below a certain level. For the underlying demand curve in blue, there are relatively few periods of peak demand (e.g. over 65GW in

GB or 6GW in the SEM), but an almost continuous system requirement of 27GW or 3GW respectively.

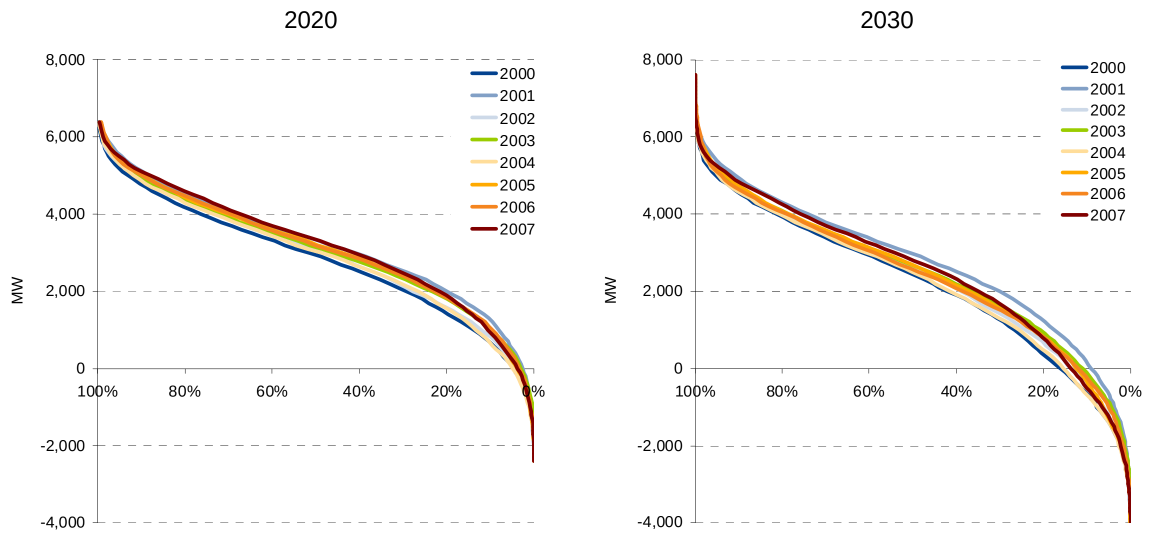
Figure 37 – Demand duration curves for GB and SEM in 2030



Installed capacity and demand from Core scenario.

The effect of installing substantial wind capacity can be seen by comparing the curves in blue and orange in Figure 37. For the SEM, the change is startling, with periods of zero or even negative demand (i.e. there is more energy generated from wind than the system requires). In addition, 3GW of thermal capacity is only required for around 50% of the hours in a year, instead of 100% for demand only. As a result, the spread of demand net wind that thermal capacity has to meet is about 7GW as opposed to 4GW without wind. The same is true for GB – the spread of demand to be met by the thermal system is almost 70GW after the effect of wind, as opposed to 35GW in a system with no wind.

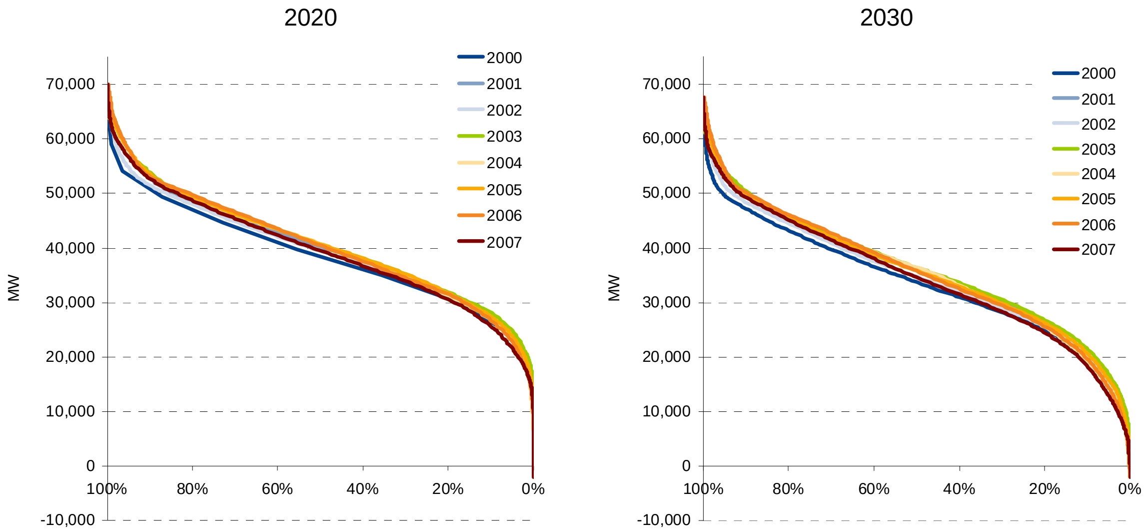
Figure 38 – Demand net wind generation for SEM 2020 and 2030



Installed capacity and demand from Core scenario.

Figure 38 shows the demand net wind for a variety of historical wind years. Unsurprisingly, there is variation between years, as a result of how demand and wind generation match, hour-by-hour. The difference between 2020 and 2030 is that wind generation can now deliver more energy than the SEM system requires and hence there are periods when the system has more energy provided than demanded; all by wind. The effect of the 'tail' has implications for base load capacity as the number of hours that a given load is required and therefore plants are required to operate reduces.

Figure 39 – Demand net wind generation for GB 2020 and 2030



Installed capacity and demand from Core scenario.

Figure 39 shows the duration curves for demand net wind generation for the GB market in 2020 and 2030. A similar pattern is visible – with variation between Monte Carlo years due to the coincidence of wind and demand. As wind generation increases, the number of periods when there is little demand to be met by thermal generation increases – in 2020, 20% of the time, demand net wind is less than 30GW, whilst in 2030, it rises to 30% of the time.

3.4.2 How does demand net wind change on an hourly basis?

The rate of change of demand net wind over time gives an understanding of the amount of thermal generation that is required to come on-line to meet demand – it gives a measure of how much ramping that the thermal system must do. The figure for ramping is calculated by subtracting demand net wind at time *t-1* from time *t*. For the purposes of this study, 1 hour ramping, 4 hour ramping and 12 hour ramping have been used.

Figure 40 and Figure 41 show 1 hour wind ramping duration curves for Monte Carlo year 2002. One duration curve is plotted for Monte Carlo year 2002 and represents the sorted hourly demand net wind value that must be met by the thermal system. It should be noted that negative demand means that less capacity would be required for the next hour while a positive value for demand indicates that more capacity is required in the next hour.

In GB both in 2020 and 2030, there is very little difference for the majority of the ramping curve – showing that demand net wind is not on average any more volatile than demand alone. However, there is a change at the extremes of the curve, which is not evident from the charts, where a small number of periods have rising demand coinciding with falling wind generation. This is shown in Table 6, where the hourly ramping requirement due to demand only in 2020 is -6.2 GW and +10.7MW. For demand net wind, the hourly ramping increases to -9.6GW and 12.8GW. In 2030, the difference is more extreme – an hourly ramping of demand of -6.0GW and +10.7GW increases to -12.4GW and 15.2GW.

In the SEM, there is more of a visible difference in the ramping duration curves, as shown in Figure 41, primarily due to the larger share of wind generation assumed for the Irish market than for the GB market, and the more volatile and correlated wind generation from the geographically smaller market. It becomes particularly evident in 2030, where the ramping for demand net wind is visibly more extreme for all of the duration curve.

Table 7 shows the hourly ramp of demand only for the SEM is a minimum of -1.1GW and a maximum of +1.1GW. Both of these figures are half that of demand net wind reported in 2020 and 2030 when wind has modified the demand profile. Therefore it can be concluded that for the SEM, the addition of a significant quantity of wind generation results in an increase in the ramping requirement that the rest of the system must deal with. Moreover, both maximum and minimum ramping requirements are affected.

Figure 40 – 1 hour ramping – duration curve GB

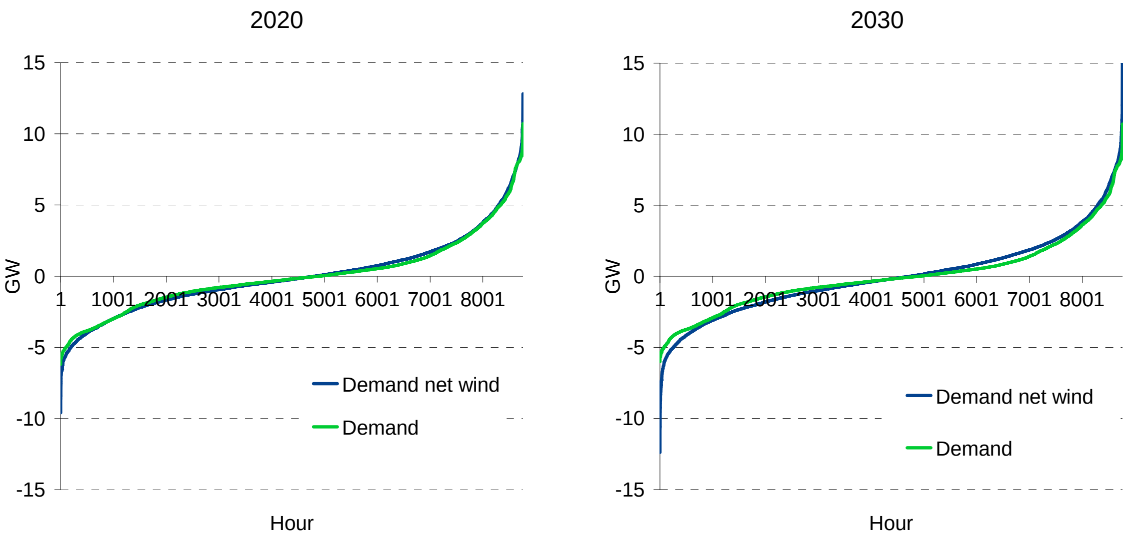
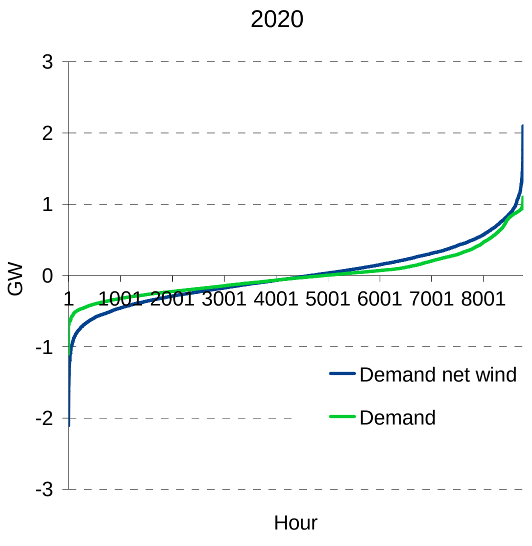


Figure 41 – 1 hour ramping – duration curve SEM



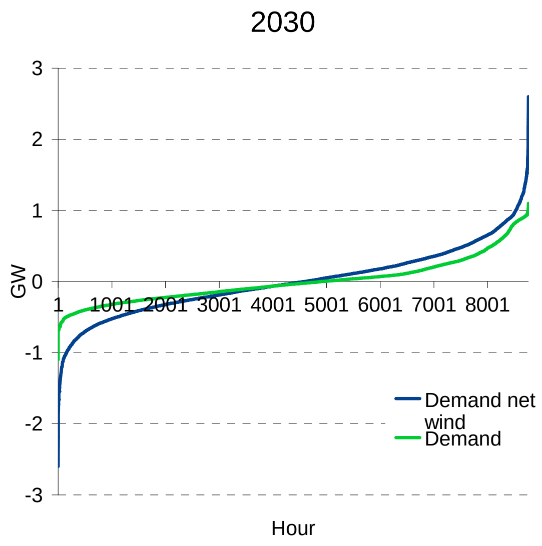


Table 6 – GB ramping

Demand

GB 2020	Min (MW)	Max (MW)
1 Hour	-6.2	10.7
4 Hour	-19.5	21.3
12 Hour	-29.8	29.7

GB 2030	Min (MW)	Max (MW)
1 Hour	-6.0	10.7
4 Hour	-19.1	21.3
12 Hour	-29.1	29.7

Demand net wind

GB 2020	Min (GW)	Max (GW)
1 Hour	-9.6	12.8
4 Hour	-27.8	27.6
12 Hour	-51.1	43.2

GB 2030	Min (GW)	Max (GW)
1 Hour	-12.4	15.2
4 Hour	-31.4	33.1
12 Hour	-59.6	50.3

Table 7 – SEM ramping

Demand

SEM 2020	Min (GW)	Max (GW)
1 Hour	-1.1	1.1
4 Hour	-2.4	2.6
12 Hour	-3.5	3.7

SEM 2030	Min (GW)	Max (GW)
1 Hour	-1.1	1.1
4 Hour	-2.4	2.6
12 Hour	-3.5	3.7

Demand net wind

SEM 2020	Min (GW)	Max (GW)
1 Hour	-2.1	2.1
4 Hour	-4.5	5.4
12 Hour	-7.3	7.3

SEM 2030	Min (GW)	Max (GW)
1 Hour	-2.6	2.6
4 Hour	-5.8	6.8
12 Hour	-8.6	8.5

As a result, it can be concluded that the one-hour ramping requirement for the GB market is broadly unaffected by large volumes of wind, although for a small number of hours where rising demand coincides with falling wind, the requirement increases. In the SEM, due to the small market and greater share of wind, the one-hour ramping requirement grows overall, as do the extremes.

3.4.3 Would there ever be no wind generation at peak demand hours?

Examining the top three demand hours[31] for each Monte Carlo year and comparing the amount of wind generated in that period illustrates the variability of wind at key system tightness. Based on actual data from 2000 to 2007 for demand and wind, Table 8 shows that there is significant variation in the contribution of wind to demand at peak demand hours, varying between a maximum of 48% in GB to a mere 1%, and between 82% in SEM and 3%. However, it does show that wind will not necessarily be present when the system is facing highest demand.

Table 8 – Percentage of peak demand met by wind generation

	SEM	GB
Max	82%	48%
Min	3%	1%
Average	32%	25%

Based on demand and wind speed data for period from 2000 to 2007, examining top 3 demand hours for each year.

3.5 Offshore wind

Offshore wind sites are expected to contribute a significant proportion of future electricity supplies for the GB market in all scenarios. As a result, it is important to understand how offshore wind may differ to onshore, and the extent to which paucity of offshore wind data may affect the results.

In total, 8 locations were chosen as being representative for offshore sites in the UK while 1 site was chosen as being representative for the limited offshore development expected in the SEM market. The data for the offshore sites was provided by the Met Office as output from their numerical weather prediction program due to a lack of recording stations in the areas that were of interest i.e. those corresponding to round two and three locations where large deployments of wind generation could be expected. The data for the offshore site in SEM was provided by Met Éireann using offshore buoy data.

Generation from offshore wind sites differs from generation from onshore wind sites in two respects: firstly there is a large concentration of installed capacity in one location and secondly the nature of offshore wind regimes compared to onshore wind regimes. These differences result in two emergent questions:

- How is offshore wind different to onshore wind?
- Is a single mast representative of a large offshore area?

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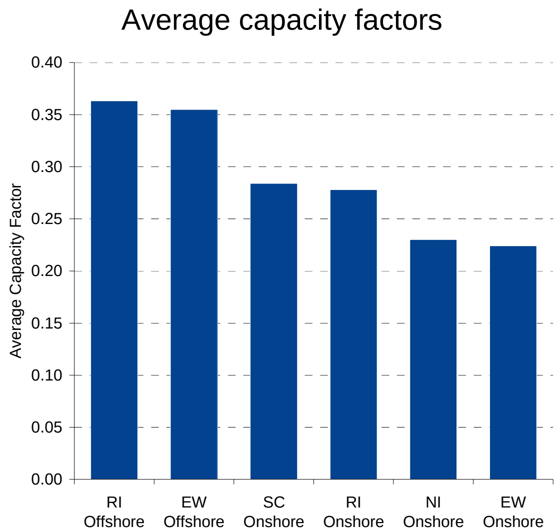
31 The peak three demand hours has been used as is similar to the Triad measure used by NationalGrid to calculate TNUoS charges

3.5.1 How is offshore wind generation different to onshore?

Offshore wind regimes exhibit significant differences to those onshore for a variety of reasons. Firstly, the absence of terrain effects means that the wind profile tends to be smoother and more constant. Secondly, the average wind speed is higher at offshore sites than onshore sites. Figure 42 illustrates the difference in average capacity factor between onshore and offshore sites for all Monte Carlo years used in the study.

Figure 42 – Comparison of offshore and onshore capacity factors



Correlation

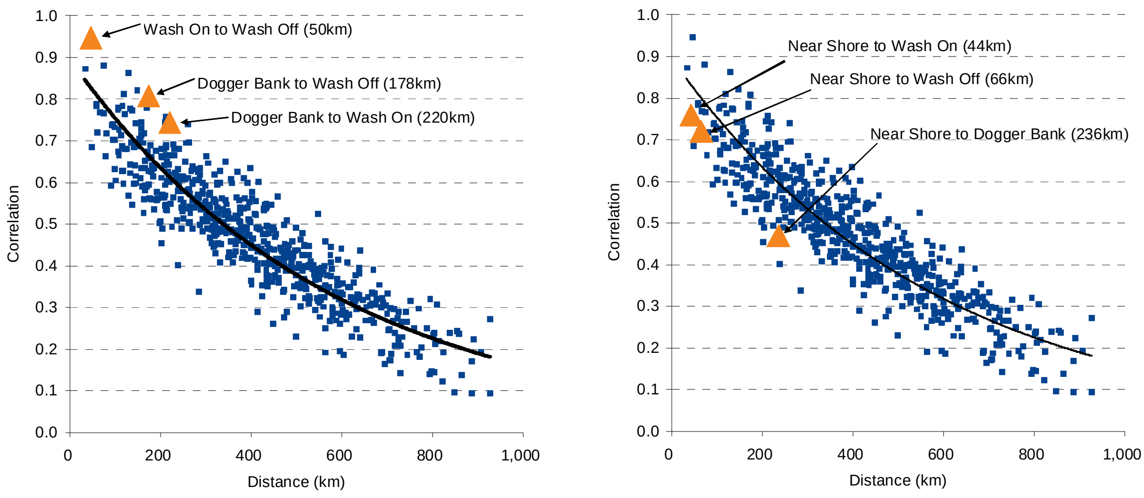
	RI Onshore	NI Onshore	SC Onshore	EW Onshore	RI Offshore	EW Offshore
RI Onshore	1	0.89	0.59	0.66	0.65	0.59
NI Onshore		1	0.66	0.62	0.63	0.54
SC Onshore			1	0.63	0.51	0.49
EW Onshore				1	0.65	0.89
RI Offshore					1	0.70
EW Offshore						1

3.5.2 Is a single wind mast a good representation of a large area?

The main complicating factor to providing an answer to this question is that currently there are no operational wind farms that approach in size the expected view of installed capacity in our Core scenario or that cover the area where Round 3 wind farms are expected. As a result of a lack of appropriate empirical data, and in order to answer this question, correlation between offshore wind sites is analysed to see if there value in increasing the number of offshore observation points. A high correlation would imply that there is little value in using another representative point, while a low correlation would imply that there is value in using another representative point for the area in question.

Significant installed capacity is expected at offshore wind sites e.g. 6GW on the Dogger Bank implying that a large area will be covered by turbines – using the BWEA recommendation of spacing turbines 2.5MW/km^2 for multiple wind farms in large areas, or 5MW/km^2 for a single wind farm, areas of up to 2500km^2 will be covered. The governing factor for the spacing figures is to control wake effects, although others such as seabed conditions are also constraints in reality. In addition, the difference between the two installed power densities is primarily due the spacing between wind farms.

Figure 43 – Correlation of wind speed for offshore sites



The graphs in Figure 43 show the correlation between two classes of offshore wind farms superimposed on the correlation between all wind farms involved in the study. The left hand graph in Figure 43 shows the correlation between offshore sites greater than 20km from the coastline is higher than expected, while the right hand graph shows that the correlation between a site close to the shoreline (within 10km) and sites further offshore is lower than expected. This is due to the boundary effect of the shoreline which means that onshore wind conditions exert influence on offshore wind conditions up to a distance of 20km off the coast. Given that most of the offshore sites described in this study are at a distance of greater than 20km from the coast, this would imply that the right hand graph, while interesting, is not applicable to the question in hand.

The higher correlation between far offshore sites implies that for a given area covered by turbines, far offshore sites will give a higher wind speed (and therefore power output) correlation than if the same area were to be covered over land. As a result, it could be argued that offshore sites will not benefit from a lack of correlation as land sites do. However, it should be noted that the increase in correlation between offshore sites may be more than compensated for by the higher capacity factors observed at offshore sites.

In terms of application to the wind model, the largest area that will be covered by turbines is likely to be 2500km^2 – for illustrative purposes this can be seen as a square of 50km by 50km. The left hand graph in Figure 43 shows that the correlation between two points 50km apart (Wash On to Wash Off) is 0.96. Using these two sites as a proxy for points at the extreme ends of a wind farm on Dogger Bank, implies that there is little value in using data from another representative point and therefore one meteorological mast is suitable as a representation of a large offshore area.

3.6 Conclusions

It is clear from the above analysis that there is considerable intermittency in wind generation, and a system with considerable installed wind capacity will have significant variations to manage. Periods of very low generation (less than 5%) across either GB or Ireland will not be uncommon, and may last up to a few days; equally there will be periods with very high wind generation.

Since the correlation of wind between two points decreases the further they are away from each other, the wind in two different locations is not the same and hence low periods of wind at one location can be offset by high wind speeds at a different location. The effect of this is to reduce the variability of wind generation. As a result, the smaller the geographic area, the more variable the wind resource will be – hence wind in the SEM has a greater variability than in GB.

There is some correlation (r^2 of 0.44) between wind in the SEM and in GB – both do experience periods when average wind speeds (or wind generation) is either very high or very low together. With our deployment of wind turbines, there are no periods when wind generation in GB is very high and at the same time very low in the SEM.

Although wind speeds on average are higher during peak hours, and are higher in winter than in summer, this is typically masked by a very significant variation of generation around the averages. Thus with our installed capacity assumptions for 2020, at triad peaks (top 3 demand hours), wind generation has been between 1% and 48% of demand in GB, and 3% and 82% of demand in the SEM.

There is considerable variation of wind speeds and hence wind generation between different years, and with an assumption of 33GW of capacity in GB in 2020, annual wind output could vary between 83-93TWh – a variation of 12%. In the SEM, a annual higher variation of 21% could be expected in 2020 with 6.1GW of capacity due to the smaller size of the market – in generation terms this is between 14.6TWh and 17.7TWh.

The demand needed to be met by non-wind capacity ('demand net wind') will be much more variable than the current demand profile. In GB in 2030, demand could vary between 30GW and 70GW. However, demand net wind may vary between zero and 65GW – considerably more as a result of the wind. In the SEM, there is a similar relationship – the spread of hourly demand across the year is 5GW but demand net wind may be 11GW.

Importantly, the potential ramping required by the thermal system will increase. Although the ramping in the majority of hours will be similar to currently, the 'worst case' ramping will increase. By 2020, the maximum hourly change that thermal generation may face is 12.7GW up and 9.7GW down. By 2030, this could have increased to 15.2GW up and 12.4GW down – thus 15.2GW of generation may have to be brought on line for a single hour in the worst case scenario. In the SEM, hourly ramping of demand net wind increases from 2.1GW in 2020 to 2.4GW in 2030. This ramping duty can be mitigated to some extent by more active demand, however the volumes suggest that this will largely require resolving by thermal plant.

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4. OVERVIEW OF CORE SCENARIO

The study explored a Core scenario in detail and a further set of 9 scenarios to examine a range of possible outcomes and areas of interest. This section provides an overview of the key inputs to the various scenarios and a summary of the main outcomes from them. The scenarios are then used for exploring a variety of topic questions in Section 6 – Topic Investigations.

The guiding principle of the Core scenario is to explore the key features of future energy markets in GB and Ireland and derive central questions for topic investigation and sensitivity testing. It does not represent a base case – it is merely a reasonable starting point for exploring a 2020 and 2030 world.

The Core scenario deliberately provides a 'stress-test' by assuming a high percentage of generation from renewables. The implied numbers are in line with other 'accepted scenarios' e.g. in GB, demand, renewables, nuclear and CCS coal are based on assumptions from National Grid's Gone Green Scenario. In the SEM (Single Electricity Market which covers Northern Ireland and the Republic of Ireland), assumptions are from the EirGrid Grid25 study[32], with additional amount of renewables up to 2030.

Renewables (wind, wave, tidal and biomass), nuclear and CCS coal capacity are assumed to be built irrespective of returns. New build of coal, OCGT and CCGT capacity in our scenarios is driven by underlying plant economics. Retiral of plant is driven by technical lifetimes or (where applicable) environmental restrictions (i.e. the LCPD or IED Directive). As a basic modelling assumption we always assume that enough capacity is built to meet demand. The tightest we allow the system to get to is a maximum of two periods of lost load per year.

4.1 Common input assumptions

This section describes the input assumptions that are the basis for the Core scenario and are largely common across all the scenarios. The discussion on each scenario covers the changes that have been made from the Core scenario inputs.

4.1.1 Demand

Demand assumptions are shown in Table 9 below. The total demand shown is the average for all Monte Carlo simulations and each simulation has different pattern of weather reflected – thus each Monte Carlo simulation gives different annual demand – for example a cold winter may lead to a higher annual demand despite all other factors being equal.

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32 EirGrid. Grid25, A Strategy for the Development of Ireland's Electricity Grid for a Sustainable and Competitive Future.

Table 9 – Demand by zone

Demand growth (CAGR)		**2008-10**	**2010-15**	**2015-16**	**2016-20**	**2020-25**	**2025-30**
England & Wales		0.0%	0.5%	0.5%	0.5%	-0.5%	0.0%
Scotland		0.0%	0.5%	0.5%	0.5%	-0.5%	0.0%
Northern Ireland		0.5%	1.0%	1.0%	1.0%	0.0%	0.0%
Republic of Ireland		0.5%	1.0%	1.0%	1.0%	0.0%	0.0%
Peak demand growth		**2008-10**	**2010-15**	**2015-16**	**2016-20**	**2020-25**	**2025-30**
England & Wales		0.0%	0.5%	0.5%	0.5%	-0.5%	0.0%
Scotland		0.0%	0.5%	0.5%	0.5%	-0.5%	0.0%
Northern Ireland		0.5%	1.0%	1.0%	1.0%	0.0%	0.0%
Republic of Ireland		0.5%	1.0%	1.0%	1.0%	0.0%	0.0%
Average demand (TWh)	**2008**	**2010**	**2015**	**2016**	**2020**	**2025**	**2030**
England & Wales	335.4	335.4	343.8	345.6	352.5	343.8	343.8
Scotland	36.0	36.0	37.0	37.1	37.9	36.9	36.9
Northern Ireland	9.1	9.2	9.7	9.8	10.2	10.2	10.2
Republic of Ireland	30.2	30.5	32.1	32.4	33.7	33.7	33.7
GB Demand	371.4	371.4	380.8	382.7	390.4	380.7	380.7
SEM Demand	39.3	39.7	41.8	42.2	43.9	43.9	43.9

4.1.2 Commodity prices and exchange rates

The fuel and carbon price assumptions are based on forward curves in December 2008, with long-term values influenced by our fuel modelling. Fuel price assumptions have deliberately been kept simple to ensure that key effects due to wind generation are not masked by changing commodity prices.

Monthly gas prices have been profiled assuming the historical monthly profile from 2000 to 2007. All fuel price inputs are on a monthly basis, in 2008 real money.

Table 10 – Fuel price assumptions

in 2008 real money		2010	2015 onwards
Brent crude oil	$/bbl	66.0	70.0
Gas GB	p/therm £/MWh	53.4 18.2	57.8 19.7
Gas SEM	p/therm £/MWh	57.1 19.5	61.5 21.0
Coal (ARA CIF)	$/t £/MWh	87.0 8.1	69.7 6.7
Carbon	£/tonne CO2 €/tonne CO2	17.4 18.7	35.0 37.8
Exchange rate	$per£ €per£	1.46 1.07	1.42 1.08
GasOil (ARA CIF)	$/bbl £/MWh	48.4 33.8	51.1 36.6
LSFO (ARA CIF)	$/bbl £/MWh	30.1 18.3	32.0 20.0
Biomass	£/MWh	10.0	10.0

All prices are at market pricing points. Gas is NBP for the GB market and at a similar notional point for Ireland.

4.1.3 Bid prices of renewables

Renewable generation such as wind, wave and tidal have a variable cost generation of zero. However, in the GB market, the subsidy from the ROC mechanism means that the opportunity cost of these technologies is below zero – in the case of onshore wind it would bid at minus one ROC, and offshore wind at minus one-and-a-half ROCs (-£59/MWh).

In the SEM, the market rules mean that plant must bid at their marginal cost of generation. Hence wind, wave and tidal in Ireland assumed to have a bid cost of zero (a ‘variable price taker’), and biomass at its fuel cost[33], whereas wind in Northern Ireland is assumed to bid at the negative of the ROC value.

33 Renewable generation currently enjoys priority dispatch in SEM which could be interpreted as a bid at the market floor price, currently -€100/MWh. The treatment of wind and priority dispatch is presently under review, and we have chosen the bid prices in order to test the implications of different bid prices for wind plants in Ireland and Northern Ireland.

Figure 44 – Bid prices of renewables

Market	Type	Bid principal
UK	Onshore wind	-1 ROC
UK	Offshore wind	-1.5 ROCs
UK	Biomass	-1.5 ROCs + fuel
UK	Tidal	-2 ROCs
UK	Wave	-2 ROCs
ROI	Onshore wind	Marginal cost
ROI	Offshore wind	Marginal cost
ROI	Biomass	Fuel
ROI	Tidal	Marginal cost
ROI	Wave	Marginal cost

4.1.4 *Interconnection*

Assumptions on interconnection capacities between GB and SEM have a significant impact in both markets. We assume three interconnectors: the existing Moyle interconnector between Scotland and Northern Ireland (assumed to have tradable capacity of 400MW), the planned 500MW East West interconnector between Wales and the Republic of Ireland and another 500MW interconnector between England & Wales and the Republic of Ireland. All capacities have been assumed to be identical in each direction in the Core scenario.

Table 11 – Interconnection assumptions GB to SEM

in GW		2010		2015		2016		2020		2025		2030	
From	To	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
England & Wales	Scotland	2.23	2.80	2.56	3.30	2.56	3.30	6.26	7.60	6.26	7.60	6.26	7.60
Scotland	Northern Ireland	0.40		0.40		0.40		0.40		0.40		0.40	
England & Wales	R. of Ireland	0		1.00		1.00		1.00		1.00		1.00	
Northern Ireland	R. of Ireland	0.42		0.68		0.68		0.68		0.68		0.68	

Note: Actual transfer capabilities for Scotland and England & Wales are based on seasonal temperature ratings and outages. The assumed summer transfer represent an average expected availability based on summer ratings and outages.

In terms of connection to Continental Europe, the interconnector to France, BritNed to the Netherlands (under development) and the planned interconnector to Belgium have been taken into account from 2015 onwards. As the study's aim is not to explore possible interconnection scenarios with the Continent, we assumed constant capacities for all years and deliberately did not include an interconnection with the NordPool market.

Table 12 – Interconnection capacities GB – Continental Europe

in GW							
From	To	2010	2015	2016	2020	2025	2030
England & Wales	France	2.0	2.0	2.0	2.0	2.0	2.0
England & Wales	Netherlands		1.0	1.0	1.0	1.0	1.0
England & Wales	Belgium		0.7	0.7	0.7	0.7	0.7

4.2 Core scenario

This section represents an overview of the main drivers and outputs from the Core scenario. More detail on specific findings from the Core scenario is provided in Section 6 (Topic Investigations), where the results are used to answer specific questions. In addition, the Appendices provide detailed information on the scenario.

4.2.1 Purpose of scenario

The Core scenario does not represent a central or a definitive base case for the future. Instead it should be understood as a reasonable starting case to explore the world in 2020 and 2030 with significant intermittent and baseload generation.

The Core scenario is intended to be internally consistent. This means that new thermal plant which is built, such as non-CCS coal, CCGTs and OCGTs, were **intended** to make sufficient returns over their lifetime to justify being built. In effect, this means that market participants have a certain element of perfect foresight in their investment decisions. Equally, if existing plant do not cover their fixed costs, they close. However, **in practice**, new-build peaking generators are required in GB by 2030 to maintain existing security of supply standards, but under present assumptions these do not make sufficient revenues to justify the investment.

We have not examined the investment case for wind, marine, biomass and CCS coal new build as the purpose of this study was not to examine the investment potential in these technologies, but rather to investigate the effect of deploying them. In effect, investment in these technologies is independent of market conditions and outlook. For renewable technologies, this is principally due to the subsidy they receive, either through the ROC (Renewable Obligation Certificate) mechanism in GB or the REFIT (Renewable Energy Feed-In Tariff) programme in the Republic of Ireland.

For nuclear, the potential rate of new build of plant and the participants able to build these plant, limits the rate of deployment of the technology, rather than (necessarily) market returns.

4.2.2 Wholesale prices

We have used the Zephyr market model to determine the outcome for prices, and in the Core scenario, wholesale prices evolve in a complex manner out until 2030.

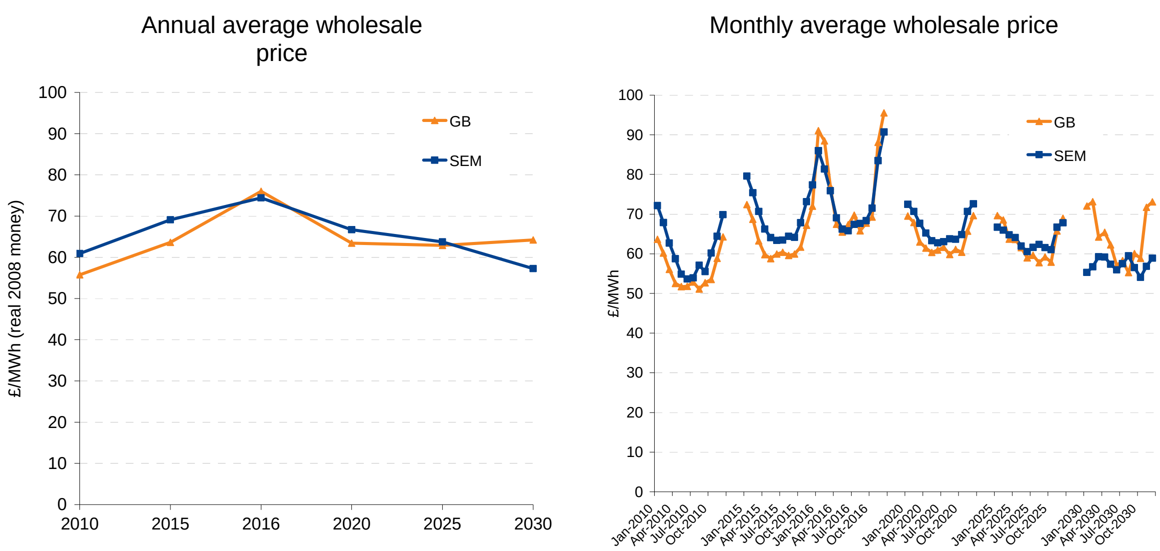
In GB, average annual wholesale prices rise from £55/MWh in 2010 to £76/MWh in 2016. The rise to 2015 is due to rising carbon prices, whilst the jump from 2015 to 2016 is due to the tightness of the system following retirement of 8GW of coal and 3GW of oil-fired plant under the LCPD. Although new entry is not required in 2016, system margins get much tighter (1.5 hours of unserved energy on average, compared to none in 2010 and 2015), which results in a higher value of capacity

From 2016 onwards, wholesale prices fall as a result of wind, nuclear, coal CCS and biomass plant being built. All these plant have much lower marginal costs and hence drive prices down. Additionally, the increasing system margin over this period means that the value of capacity component of prices in GB reduces from the highs in 2016.

Average prices in the SEM are higher than GB until 2025, due to the combination of higher gas prices (Irish gas prices are typically based of the NBP price plus a premium), and more expensive types of generation. However, SEM prices fall below GB prices in 2030 due to the very high volumes of wind generation in the Irish market. Generators in the SEM benefit from high prices in GB – the interconnection to GB means that the SEM ‘imports’ high GB prices, which would otherwise be much lower.

Prior to 2020, monthly prices exhibit a strong seasonal pattern as is currently the case, with higher prices in winter and lower in summer, due to the combination of higher electricity demand and higher gas prices. However, from 2020 onwards, this pattern is much weaker resulting in a flattening of the seasonal profile. By 2030 in the SEM, the traditional summer/winter profile has reversed, due to the large number of zero priced periods in winter from large volumes of wind generation. In GB, the relationship reasserts itself in 2030, as the system becomes tighter due to retiring older plant. This leads to a requirement for new build of plant and higher prices in peak winter hours.

Figure 45 – Annual and monthly wholesale prices in GB and SEM



2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.8	63.6	76.0	63.4	62.9	64.2
SEM	60.9	69.1	74.4	66.7	63.7	57.3

Note: All prices are time-weighted average (TWA) – i.e. the simple mean of all hourly prices.

In the Core scenario, the value of capacity component of prices varies over time, as shown in Table 13. In 2010 and 2015, the value is around £4/MWh, but this rises sharply in 2016 to almost £16/MWh, as the system tightens and is on the verge of new entry. However, with new renewables build and new nuclear the system becomes less tight and it drops back to £5/MWh in 2020 and 2025. In 2030, the value rises once more as new entry is needed.

To achieve this, the VoC multiplier rises from 6 in 2010, to 8.5 in 2016, up to 14 by 2030. Although the multiplier is identical in 2015 and 2016 at 8.5, the value of capacity rises from £3.7/MWh to £15.7/MWh as a result of the system becoming much tighter – more periods with a tight system margin lead to more periods of higher value of capacity.

Table 13 – Value of capacity and multiplier for GB

	Multiplier	Value of Capacity £/MWh	SMP £/MWh	Value of Capacity £/MWh	Wholesale price £/MWh
2006	1.0	3.8			
2007	1.0	4.7			
2008	1.0	13.8			
2010	6.0	4.5	51.2	4.5	55.8
2015	8.5	3.7	59.9	3.7	63.6
2016	8.5	15.7	60.3	15.7	76.0
2020	8.5	5.2	58.3	5.2	63.4
2025	10.3	6.5	56.4	6.5	62.9
2030	14.3	12.0	52.2	12.0	64.2

4.2.3 New build

The methodology used to determine new build and the types of new build is described in Section 2.6. In the short-term, units that are under construction or at an advanced stage are assumed to be built irrespective of returns, whilst in the longer-term, returns on plant are important for the type and quantity of plant built.

For GB, the assumptions for new large-scale plant are shown in Table 14, with a total of 6.7GW of new CCGTs built in the Core scenario between 2009 and 2013. In addition to the named plant below, there are also increases in interconnection to the Continent and between GB and the SEM (as detailed above in Section 4.1.4) of almost 3GW, along with additional CHP (approx. 1GW by 2015).

As a result of this new plant and the extra renewables built (an additional 9GW of wind by 2015), no new plant is specifically required to cover the closure of plant under the LCPD in 2016, however, this does lead to a much tighter system overall, with 1.5 periods of unserved energy in 2016 – close to our maximum of two periods.

Table 14 – New named plant commissioning in GB

Unit	MW	Year Commissioned*	First Year in Model
Langage 1	885	2009	2010
Grain 5	425	2010	2010
Immingham Extension	450	2010	2010
Marchwood	850	2010	2010
Grain 6	425	2011	2015
Grain 7	425	2011	2015
Severn Power	800	2011	2015
Staythrope 1	400	2011	2015
Staythrope 2	400	2012	2015
Staythrope 3	400	2012	2015
Carrington	860	2012	2015
Staythrope 4	400	2013	2015
Total	**6,720**		

- Note: Since not all years are modelled, the year commissioning has no effect on results – the 'first year in model' is when the plant is first modelled.

In the SEM, the new named plant assumed to be built are shown in Table 15. The Marina MRT is a conversion of an existing unit.

Table 15 – New named plant commissioning in the SEM

Unit	Type	MW	Year Commissioned*	First Year in Model
Marina_MRT	OCGT	85	2009	2010
Aghada CCGT	CCGT	431	2010	2010
Whitegate CCGT	CCGT	445	2010	2010

* Note: Since not all years are modelled, the year commissioning has no effect on results – the 'first year in model' is when the plant is first modelled.

Figure 46 shows the installed capacity by plant type in the GB market in the Core scenario. In this scenario, a significant volume of new wind generation is built. In particular, total installed wind capacity amounts to 32GW in 2020; rising to 46GW in 2030 (the location of this wind is detailed in Figure 22). Additionally, there is 1.6GW of new nuclear built by 2020, rising to 9.6GW by 2030. This is counteracted by closures of existing nuclear plant, so that by 2030, 10.7GW of nuclear is on the system.

No non-CCS coal is built in the Core scenario, owing to low returns on this type of plant[34], and only CCS plant are built – 3.2GW by 2030 in total. Furthermore, we assume a strong growth in biomass, with a total of 4.4GW being installed by 2030.

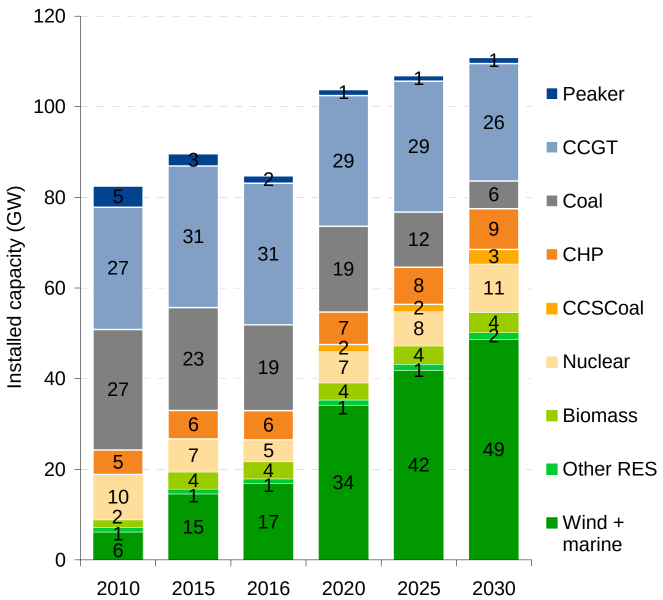
Of the older CCGTs, 2.4GW close in 2020 as they do not cover their fixed costs on an annual basis, and a further 5GW close by 2030 – due to the combination of fixed cost recovery and the age of the plant.

[34] This is a nominal unit of 200MW to assess returns of supercritical coal plant – and is not considered 'new entry'

An extra 2GW of new build is required in 2030 to cover the closure of the older CCGTs and coal plant. Additionally, a further 1GW of OCGT is built in 2030 to ensure that security of supply is maintained – this is discussed above in Section 4.2.1 and Section 2.6

Figure 46 – Installed capacity by plant type in GB in the Core Scenario

Installed capacity in the Core scenario in GB



Installed capacity in GB

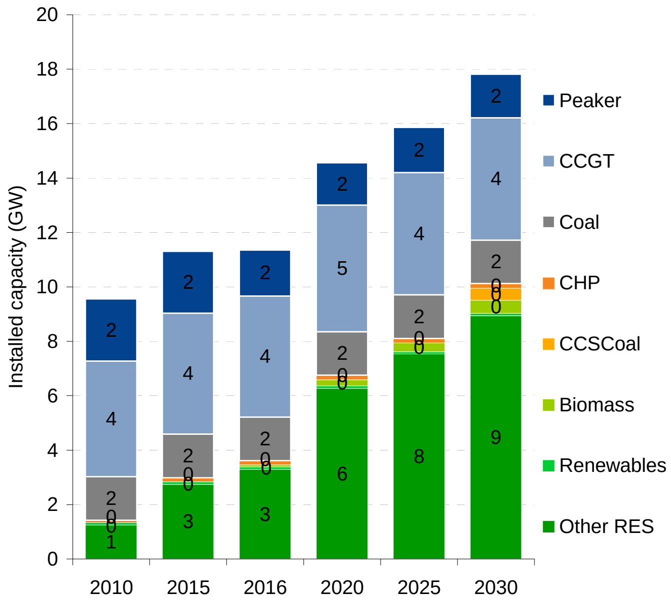
	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Wind	6.1	14.5	16.8	32.7	37.3	43.1
Wave	0.0	0.0	0.1	0.9	1.5	2.1
Tidal	0.0	0.0	0.0	0.5	3.0	3.5
Other RES	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT_E	12.4	12.4	12.4	10.0	10.0	5.1
CCGT_F	14.6	18.8	18.8	18.8	18.8	20.8
Gas Steam	0.7	0.7	0.7	0.7	0.7	0.0
Old GT Gas	0.3	0.3	0.3	0.3	0.3	0.1
Old GT Gasoil	0.9	0.7	0.7	0.3	0.2	0.2
New GT Gasoil	0.0	0.0	0.0	0.1	0.1	1.1
Oil Steam	2.8	1.0	0.0	0.0	0.0	0.0

Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

In the SEM, there is a similarly fast growth in installed wind capacity, from 1.2GW in 2010 to 6.3GW by 2020 and 8.9GW by 2030. In this scenario, wind rises to a higher penetration of the SEM than the GB market. There is a small growth in CCGT capacity as returns for CCGTs are sufficiently high to encourage a small amount of new entry. Peaking generation does not grow significantly, although the amount of peaking generation is much greater in the SEM than in GB. There is also build of a single more advanced OCGT design with a higher efficiency but commensurate higher capital costs.

Figure 47 – Installed capacity by plant type in the SEM in the Core scenario

Installed capacity in the Core scenario in the SEM



Installed capacity in the SEM

	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Wind	1.2	2.7	3.3	6.1	7.0	7.9
Wave	0.0	0.0	0.0	0.1	0.3	0.6
Tidal	0.0	0.0	0.0	0.1	0.3	0.4
Other RES	0.1	0.1	0.1	0.1	0.1	0.1
Biomass	0.0	0.0	0.1	0.2	0.3	0.5
CCSCoal	0.0	0.0	0.0	0.0	0.0	0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Gas Steam	0.6	0.6	0.6	0.3	0.3	0.3
Advanced GT	0.0	0.0	0.0	0.2	0.2	0.2
New GT Gas	0.5	0.7	0.7	0.5	0.7	0.7
New GT Gasoil	0.4	0.4	0.4	0.4	0.4	0.3
Oil Steam	0.9	0.6	0.1	0.1	0.1	0.1

Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

4.2.4 Generation and load factors

As shown in Figure 48, the GB market is dominated by coal, CCGT and nuclear in 2010. Over time, this is replaced by increasing amounts of wind and, to a lesser extent, marine, leading to 30% of generation from renewables by 2020, and 43% by 2030. Generation from nuclear drops as older plants close and reaches a low of 30TWh of generation in 2016. However, due to new build of nuclear this rises to 83TWh by 2030. In SEM, the shift is even greater, with 49% of generation from renewables in 2020 and 64% by 2030. CCGT and coal generation drops from over 30TWh in 2010 to 12TWh by 2030.

Figure 48 – Generation in GB and the SEM

Generation in GB

in TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Renewables	4.7	4.9	4.9	5.3	6.0	6.8
Biomass	9.9	22.5	22.5	22.5	24.4	24.5
Nuclear	60.2	44.5	30.4	47.7	58.7	82.8
CCSCoal	0.0	0.0	0.0	10.5	10.3	19.6
CHP	29.2	34.0	34.9	38.6	42.8	42.3
Coal	131.8	108.5	102.5	82.3	44.6	15.2
CCGT_E	30.1	5.9	10.5	3.3	3.0	0.6
CCGT_F	92.9	111.4	115.4	94.3	83.0	65.4
Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gas	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
New GT Gas	0.0	0.0	0.0	0.0	0.0	0.0
New GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
Oil Steam	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.8	366.1	361.9	397.0	388.1	393.5

	2010	2015	2016	2020	2025	2030
Wind + marine	4%	9%	11%	23%	30%	35%
Renewables	1%	1%	1%	1%	2%	2%
Biomass	3%	6%	6%	6%	6%	6%
Nuclear	16%	12%	8%	12%	15%	21%
CCSCoal	0%	0%	0%	3%	3%	5%
CHP	8%	9%	10%	10%	11%	11%
Coal	35%	30%	28%	21%	12%	4%
CCGT_E	8%	2%	3%	1%	1%	0%
CCGT_F	25%	30%	32%	24%	21%	17%
Gas Steam	0%	0%	0%	0%	0%	0%
Old GT Gas	0%	0%	0%	0%	0%	0%
Old GT Gasoil	0%	0%	0%	0%	0%	0%
New GT Gas	0%	0%	0%	0%	0%	0%
New GT Gasoil	0%	0%	0%	0%	0%	0%
Oil Steam	0%	0%	0%	0%	0%	0%
Total RES	7%	17%	19%	30%	38%	43%

Generation in the SEM

in TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Renewables	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.8
CHP	0.7	1.1	1.1	1.2	1.1	0.9
Coal	11.6	8.8	9.1	6.8	6.1	4.9
CCGT	21.7	15.8	18.1	11.6	9.9	7.0
Gas Steam	0.1	0.1	0.5	0.0	0.1	0.0
Advanced GT	0.0	0.0	0.0	0.1	0.1	0.1
New GT Gas	0.0	0.0	0.2	0.0	0.0	0.0
New GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
Oil Steam	0.1	0.1	0.0	0.0	0.0	0.0
Total	38.2	34.0	39.2	38.9	40.6	44.0

	2010	2015	2016	2020	2025	2030
Wind + marine	8%	21%	22%	44%	51%	56%
Renewables	2%	2%	2%	2%	2%	2%
Biomass	0%	0%	1%	4%	5%	6%
CCSCoal	0%	0%	0%	0%	0%	6%
CHP	2%	3%	3%	3%	3%	2%
Coal	30%	26%	23%	17%	15%	11%
CCGT	57%	47%	46%	30%	24%	16%
Gas Steam	0%	0%	1%	0%	0%	0%
Advanced GT	0%	0%	0%	0%	0%	0%
New GT Gas	0%	0%	0%	0%	0%	0%
New GT Gasoil	0%	0%	0%	0%	0%	0%
Oil Steam	0%	0%	0%	0%	0%	0%
Total RES	10%	24%	26%	49%	57%	64%

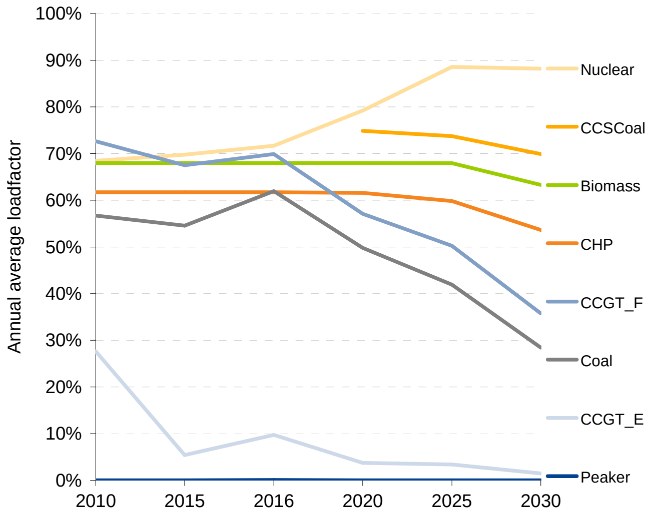
Given the very large amounts of zero marginal cost generation entering the market, it is unsurprising that the load factors of coal and gas plant are significantly affected. The temporary rise in coal load factors from 2015 to 2016 is due to the limited hours plant being shut with the LCPD, and following this, non-CCS coal plant experiences a sharp reduction in load factors, falling to 50% in 2020 and 30% by 2030. Older E-class CCGTs see a dramatic drop in their load factors to below 5% by 2020, whilst the newer F-class CCGTs also see a sharp drop to under 40% by 2030.

Nuclear load factors rise to 2030 as older, lower availability plant are shut and replaced by more modern plants. By 2030, the large volumes of wind also affect CCS coal, CHP and biomass, depressing operating hours for all these plant.

In GB, peaking generation barely runs – the load factors in the table in Figure 49 of 0.1% correspond to less than 8 hours of generation a year. This compares to the SEM where peaking plant run at somewhat higher load factors.

Figure 49 – Plant load factors in GB

Plant load factors in GB



Plant load factors in GB

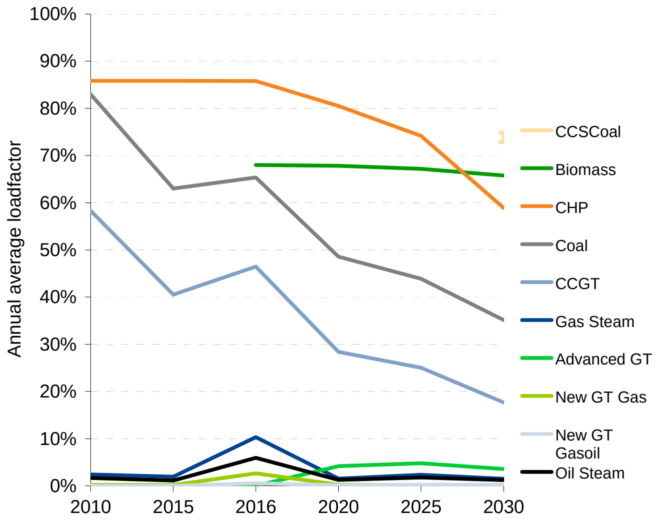
	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	63%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	28%	5%	10%	4%	3%	1%
CCGT_F	73%	67%	70%	57%	50%	36%
Coal	57%	55%	62%	50%	42%	28%
Gas Steam	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Old GT Gas	0.0%	0.1%	0.1%	0.0%	0.0%	0.1%
Old GT Gasoil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New GT Gas	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New GT Gasoil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oil Steam	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

In the SEM, load factors of both coal and CCGT plant are reduced significantly as a result of the higher wind penetration. Load factors of both coal and CCGTs rise in 2016 due to the high prices in GB – exports from GB to SEM drop significantly and load factors in Ireland rise. After 2016, coal load factors keep falling, dropping to under 50% by 2020 and to 35% in 2030, whilst CCGTs have load factors below 20% by 2030.

Wind also impacts load factors of CHP plant, reducing them to 60% in 2030. Peaking generation runs more in the Irish market, due to the combination of higher wind generation and a smaller market.

Figure 50 – Plant load factors in the SEM

Plant load factors in the SEM



Plant load factors in the SEM

	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						74%
CHP	86%	86%	86%	81%	74%	59%
Coal	83%	63%	65%	49%	44%	35%
CCGT	58%	41%	46%	28%	25%	18%
Gas Steam	2.4%	1.9%	10.3%	1.5%	2.4%	1.5%
Advanced GT	0.0%	0.0%	0.0%	4.2%	4.8%	3.6%
New GT Gas	0.2%	0.2%	2.6%	0.2%	0.2%	0.1%
New GT Gasoil	0.0%	0.0%	0.5%	0.2%	0.2%	0.2%
Oil Steam	1.7%	1.1%	6.0%	1.3%	1.8%	1.3%

4.2.5 New build plant returns

The Core scenario has been developed with the intention of ensuring consistency between new build and investment returns. However as noted above; in order to maintain security of supply we have had to assume some build of OCGT which is apparently uneconomic given existing assumptions, which only consider the present levels of ancillary service payments and the limited sources of revenue to low-merit generation under the existing GB market arrangements.

Figure 51 shows the assumptions on capital and fixed costs for new build plant in the UK and the Republic of Ireland, along with the economic lifetime and economic construction time. Further detail on how the IRRs are calculated is included in the Appendices. Indicatively, we consider IRRs (pre-tax real, hurdle rates) of between 8-12% as sufficient to incentivise new entrants.

Plant in GB

It is important to note that the existing relationship between system margin and the capacity component of wholesale price is assumed to change in order that new entry is sufficiently rewarded. Our modelling assumes that at any given level of system margin the value of capacity is significantly higher than at present (although the average levels on a time-weighted average basis are similar), and assumes that plants operating at the relevant times are able to capture the capacity value for those hours. However, these assumptions alone are not sufficient to reward new build peaking generation.

Returns for plant in GB vary significantly. The highest returns are for nuclear, which makes in excess of 11% IRR for all the years of our analysis. Nuclear does not have volume risk, as its low variable cost means it generates at baseload. Additionally, the carbon price of £35/tCO_2 (38€/tCO_2) and the zero carbon emissions from nuclear increase returns.

In this scenario, returns for new build coal plant both with and without CCS are very low. Conventional coal has returns below 4%, resulting in no conventional coal plant built in this scenario[35]. For coal CCS, returns are about 6.5% in 2020 onwards. These would not be sufficient to incentivise new plant to be built.

Returns to new build CCGTs are around 8% in 2015 and 2016. The drop in 2020 is due to the significant increase in wind, nuclear and CCS coal generation which puts downwards pressure on load factors and prices. The rise in 2030 is due to the requirement for new entry as older coal and gas plant retire.

In our Core Scenario we assume the build of around 1GW of OCGT capacity by 2030 in order to maintain system margins and a reasonable level of market prices for other plants on the system. Peaking plant make returns less than zero, largely because their load factors are not sufficiently high to allow them to capture sufficient market income to cover their capital costs, as income in GB is assumed to be available to plants only when they are operating.

There are other means by which generators could capture the capacity value apart from capturing very infrequent price spikes in a pay-as-bid market, without resorting to a capacity mechanism. The most obvious is an increase in the revenues earned by generators offering reserve and flexibility to the system operator. Alternatives include the use of peaking generators to offer option contracts to other market participants. The present BETTA market is too illiquid (in short timescales) and with too much basis risk between the various trading, balancing and imbalance prices for these risk-management products to deliver secure returns to peaking generation, but in principle there is scope for further development.

We conclude that in order for security of supply to be maintained at current levels there would need to be a material increase in the capacity value accrued, especially by peaking and low-merit generators, compared with that in evidence in today's market.

Plant in the SEM

The main difference between returns for plant in GB and the SEM is due to the Capacity Payment Mechanism (CPM) in the Irish market. Given that plant are paid for their availability rather than their generation, revenues of peaking plant increase significantly. As a result, peaking plant have IRRs of around 9% in the SEM, whereas equivalent plant in GB have returns of less than zero. More efficient Advanced GTs show lower returns as although their load factors are higher, the much higher capital costs drive down returns.

The high prices in the GB market caused by the capacity tightness in 2016 increase prices in the SEM as well – leading to a benefit caused by price linking between the SEM and GB. CCGTs experience this effect in 2015 and 2016 which pushes IRRs upwards. However, the large amount of wind generation in the SEM leads to an unfavourable environment for CCGTs which see IRRs pushed downwards to 6.3% by 2030.

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35 A single 200MW coal unit is built in 2015 in our scenarios. This is only included to allow IRRs to be calculated for this plant, and is not considered to be likely in reality.

Figure 51 – Internal Rate of Return on generation by type

Assumptions on plant economics

	Capital Cost (€/kW)	Annual Fixed Cost (€/kW)	Econ. lifetime	Econ. build time
Nuclear	2500	£120 (includes variable costs)	25	5
CCSCoal	2100	50	20	4
Coal	1500	36	20	4
CCGT	750	32	20	2
New GT	430	29	20	2

IRRs in the Core Scenario in GB

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.2%	11.6%	11.8%
CCSCoal	N/A	N/A	N/A	6.4%	6.5%	6.5%
Coal	N/A	N/A	3.6%	2.7%	3.4%	3.9%
CCGT_F	5.0%	7.6%	8.2%	6.2%	8.0%	9.4%
OCGT	<0	<0	<0	<0	<0	<0

IRRs in the Core Scenario in the SEM

	2010	2015	2016	2020	2025	2030
CCGT	N/A	8.1%	8.1%	7.0%	6.5%	6.3%
CCSCoal	N/A	N/A	N/A	N/A	N/A	4.4%
Advanced GT	N/A	2.6%	3.6%	6.5%	6.6%	6.7%
OCGT (Gasoil)	8.9%	9.2%	9.3%	8.6%	8.5%	8.8%

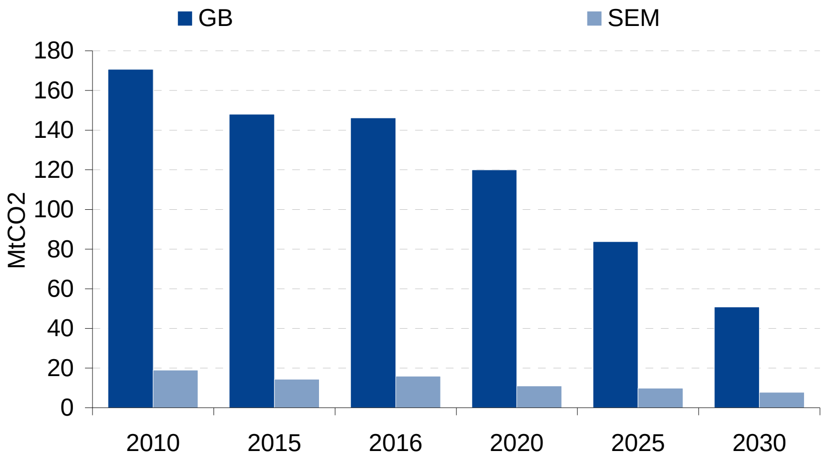
Note: IRRs are pre-tax real hurdle rates. For OCGT plant, £35/kW revenue is assumed for ancillary service payments in GB, whilst in the SEM this is £6.5/kW (€7.05/kW). Returns calculated for plant commissioning for year in question, returns for period post-2030 assumed to be at 2030 values.

4.2.6 Emissions

With the very significant volumes of renewable generation in the Core scenario, it is unsurprising that carbon emissions drop in both markets, as shown in Figure 52and Figure 53. In GB, emissions drop from 170MtCO_2 in 2010 to 50MtCO_2 in 2030 – a drop of two-thirds. This leads to an emissions intensity (the amount of CO_2 emitted per unit of generation) falling from 460gCO2/kWh down to 130gCO2/kWh by 2030. Although this is a significant drop, it is not quite as far as the Committee on Climate Change aspiration of 100gCO2/kWh. In part this is due to the 6GW of non-CCS coal generation still in operation in 2030 – these are responsible for about a quarter of emissions by 2030.

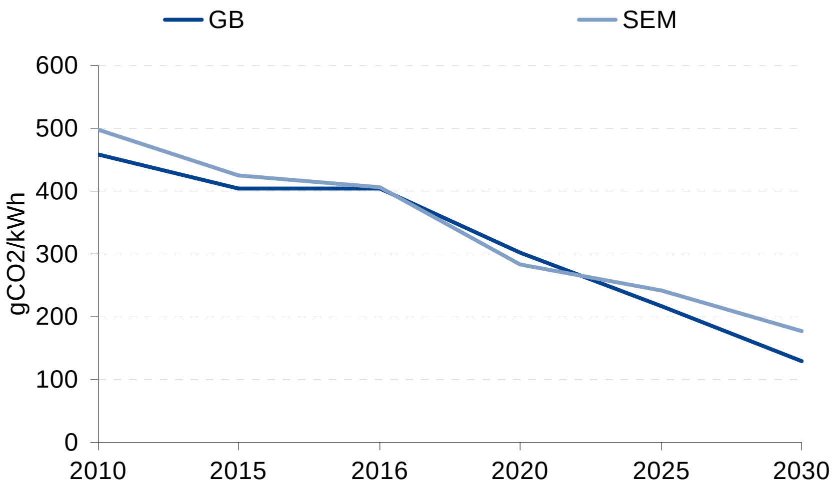
In the SEM, emissions drop from 20MtCO_2 in 2010 to 8MtCO_2 by 2030 – slightly less than a two-thirds drop. In the SEM, emissions intensity starts from a higher base than GB at almost 500gCO_2/kWh, owing to coal and peat plant. However, by 2030, this has fallen to 177g$C0_2$/kWh. Over half of the emissions are from the 1.6GW of coal plant still open (Moneypoint, Shannonbridge and Kilroot).

Figure 52 – Carbon emissions in the Core scenario



MtCO2	2010	2015	2016	2020	2025	2030
GB	171	148	146	120	84	51
SEM	19	14	16	11	10	8

Figure 53 – Carbon emissions intensity in the Core scenario



gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.1	404.2	403.6	302.1	215.8	129.1
SEM	497.0	424.2	406.3	283.5	241.5	177.6

4.2.7 Detail on February 2030

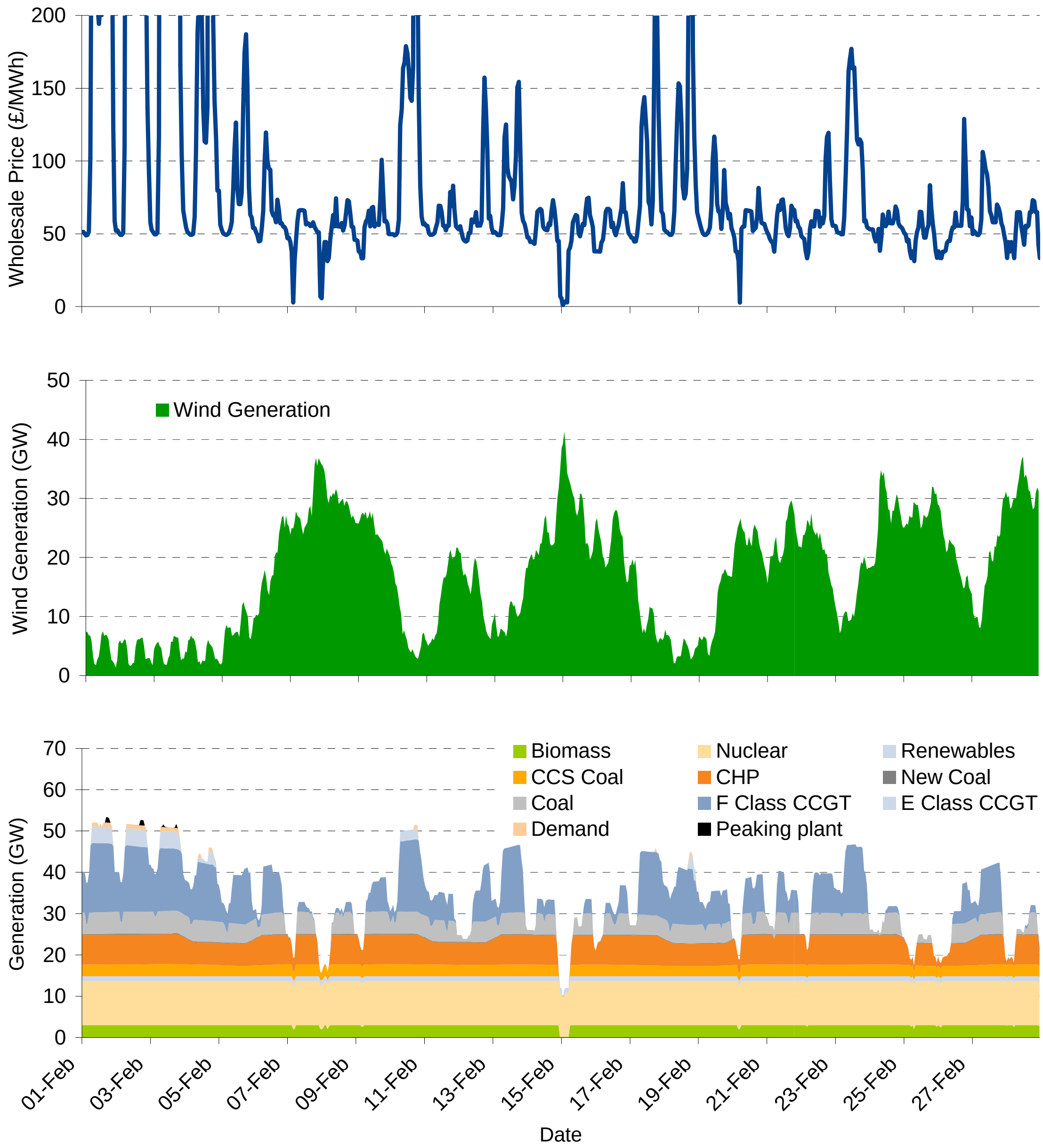
Figure 54 and Figure 55 show hourly wind generation, thermal generation and wholesale prices from the Market Schedule runs for February 2030 using underlying data from

February 2006. Detailed information on two further months – January 2030 using January 2000 data and November 2030 based on November 2001 are given in the Appendices.

The UK experienced an average temperature of 3.6℃ in February 2006, making the month the coldest February in the UK since 1996. A fire broke out at the Rough storage facility on 16th February, taking out the UK's biggest supply of storage gas, which was out of service for the remainder of the month into March.

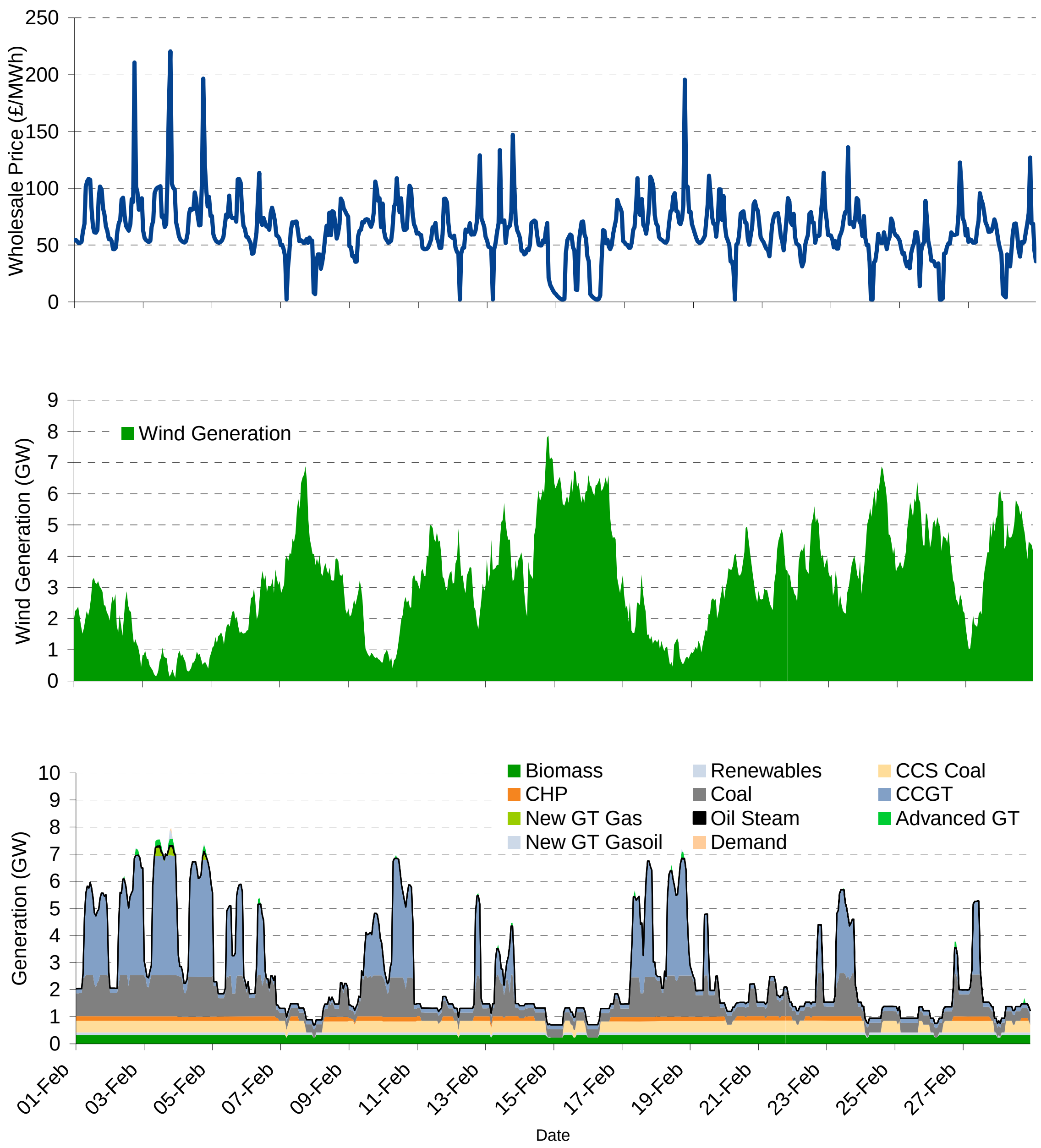
The beginning of the month was marked by a high pressure area bringing very low temperatures, with average temperatures dropping to -1.4^{o}C on 2 February. As a result, demand was very high, but wind speeds were very low. Between the 7th and the 8th of the month, a cold front pushed southwards allowing a brisk northerly wind to sweep across the country, bringing plenty of wintry showers. For the majority of the remainder of the month, the UK experienced cold and showery weather.

Figure 54 – GB system profile in 2030 based on February 2006



In GB, prices in 2030 become extremely high for the first 5 days of the month due to the combination of high demand and low wind generation, with peaking plant running on a series of days. By 7 February with a significant increase in wind generation, all of the thermal plant is forced from the system, including some CCS coal. This leads to periods of low prices for two days. The 15 February has the highest wind generation of the period which occurs overnight, with 40GW of generation, leading to some nuclear plant being displaced.

Figure 55 – SEM system profile in 2030 based on February 2006



The SEM was affected in a less dramatic fashion at the beginning of February, as wind generation remained relatively high for the first two days. From 3 February, wind generation drops which causes spikes in wholesale prices, with peaking generation running. From 7 February, the upsurge in wind generation causes a series of periods of zero prices, and CCS coal plant do not run for some periods.

4.2.8 Conclusions

The Core scenario is challenging in terms of the rate at which new renewable capacity must be installed and the total amount that is deployed.

The Core scenario leads to fundamentally different energy markets. Retirement of LCPD plant and 2020 targets create an investment conundrum in GB – with significant volumes of low carbon generation being built from 2016 onwards, investing in thermal plant for 2016 is risky as a company would need to recover its investment in a short period of time before revenues are driven downwards by wind and nuclear. Thus an energy-only market requires high prices to incentivise new entry to 'keep the lights on'.

BETTA and SEM lead to different outcomes regarding new entry. The energy-only market in GB leads to no **economic** OCGT new-build, as peaking plant do not run sufficiently to recover their investment. However, we do find a need for up to 1GW of peaking generation in GB by 2030. Even with the multiplier which we assume is applied to the value of capacity, peaking generation is not sufficiently rewarded to justify its build, given assumptions on ancillary service revenue and the operation of the market. In Ireland, the CPM leads to OCGTs being more profitable than CCGTs.

The Core scenario is a world where thermal plant are increasingly used as mid- and peaking plant to balance the intermittency of wind, leading to much lower load factors than at present. In this scenario, coal and CCGT load factors are dramatically depressed by wind. In particular, the older CCGTs in GB ('E-class') have load factors that mean many do not recover fixed costs and as a result close down.

The findings and results from the Core scenario are discussed in more detail as part of Section 6 – Topic Investigations.

5. SUMMARY OF FURTHER CASES

5.1 Overview of the further cases

A series of further cases has been run to explore specific areas of interest. These are outlined in this section. More comprehensive results are given in the Appendices.

The distinction between a scenario and a sensitivity is whether the new build assumptions are internally consistent. In a scenario we ensure that conventional new entrants (except OCGT) are able to fully recover their investment costs by changing new build, value of capacity and retiral of plants. In a sensitivity, one of the inputs for a scenario is changed, without ensuring full consistency of new build. Table 16 below summarises the scenarios.

Table 16 – Overview of scenarios and sensitivities

Scenario	Key question	Description
Core scenario	What is the impact of intermittency on the markets of GB and SEM?	High deployment of wind and baseload generation in GB and SEM
Capacity payment scenario	If a capacity payment mechanism existed in the GB market, how might it change outcomes?	The capacity payment mechanism in the SEM is implemented in the GB market
Lower RES scenario	How does a less stretching renewables case affect our results?	In GB there is 6GW less wind in 2020 and 15GW less in 2030 than in the Core scenario, and 1.5GW in 2020 and 3.5GW less in 2030 in SEM
Carbon drop scenario	To what extent are the results changed with a different coal-gas relativity?	The carbon price is reduced to £20/tCO_2 from £35/tCO_2 in the Central case
IED scenario	How does a strict implementation of the IED change the requirements for new build?	5GW of coal and 8GW of CCGTs close in 2020 in GB in addition to those closed in 2016 due to the LCPD
Offshore deployment sensitivity	Does more geographically concentrated wind build with significant deployment on the Dogger Bank affect the market?	Increased deployment on Dogger Bank from 6GW to 13GW, with reduced deployment elsewhere
Severn barrage sensitivity	How does a 10GW barrage affect the market?	Scenario assumes the 1GW Shoots barrage and another 1GW scheme with the same profile are replaced by a single 10GW Cardiff-Weston barrage
Interconnection sensitivity	What is the impact of a smaller interconnector between GB and Ireland	Scenario assumes 400/80MW Scotland to NI and 500MW both ways ROI to E&W
Inflexible demand management scenario	How does a flatter demand profile from inflexible Demand Side Response change our results?	Assumes an increase in electric heating and electric vehicles that leads to a flatter demand profile
Price responsive demand management scenario	How would price responsive demand side management (smart meters) change our results?	Scenario assumes deployment of smart meters which allow dynamic load management

5.2 Capacity payment scenario

The Capacity payment scenario assumes that a Capacity Payment Mechanism (CPM) based around that already existing in the SEM is implemented in GB. We analyse the potential effect on prices, new build requirements and their returns, and the knock-on implications for Irish market.

The core scenario assumes that sufficient capacity is available to maintain security of supply and includes some (uneconomic) build of OCGTs at the end of the period. Therefore the implications of a CPM on system security have not been directly evaluated, other than to note that its existence does make OCGT build economic. In practice there are other means to ensure security of supply, including development of the market to include trading of peaking option contracts, increased ancillary service payments or the inclusion of the demand-side in the market in a meaningful way.

The CPM in the SEM remunerates generators for being available, rather than just for generating. This means that plants know for certain that they will earn a capacity payment when available, even if they are not in merit and thus not generating.

The total annual sum paid by consumers to generators in the SEM CPM is based on the cost of a new entrant peaker in €/kW terms (net of ancillary service revenue and infra-marginal rent from operation in the energy market) multiplied by the kW required in the year to meet the all-island security standard. The annual payment is also split into monthly pots based on projected demand before the start of the year in question and further into half-hours based on a variety of forecast and outturn metrics intended to act as a proxy for the system margin. The result is a very smoothed set of capacity prices compared to the theoretical value of capacity.

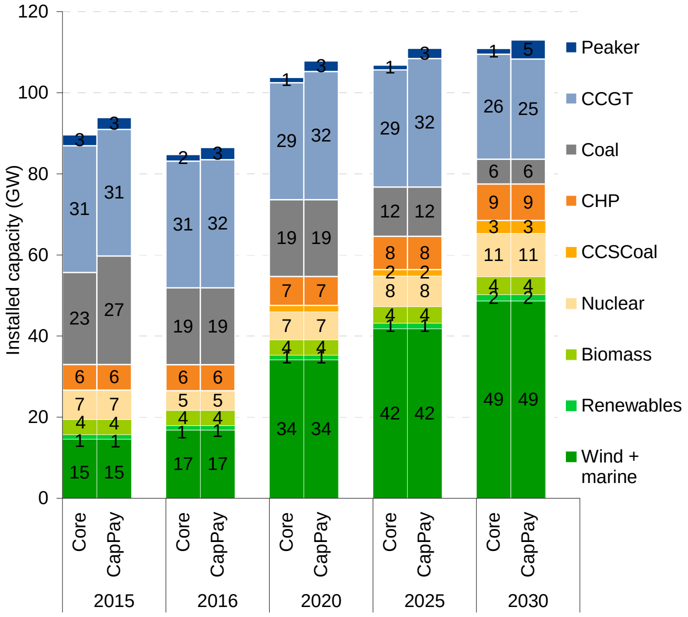
Within the CPM case we have made the key assumption that generators (and demand) would bid into the energy market at their short run marginal cost. In practice at times of scarcity, even with a capacity mechanism, generators might be able to achieve above marginal cost prices in the energy market and thereby be rewarded twice for the provision of capacity. The dynamic of this is complex, but we note that in the SEM there is a licence requirement for generators to bid in line with short-run marginal cost principles and that this was (in part) justified in order to avoid double payment for the provision of capacity. The SEM variant of a capacity mechanism is designed to deliver a smoothed profile of capacity prices, but other designs may still deliver volatile capacity revenues.

5.2.1 Changes compared to the Core scenario

To obtain a consistent scenario in terms of new build investments, new plant capacities are altered in the Capacity Payment scenario. Over 4 GW of additional OCGTs are built in 2030, along with less retiral of older CCGTs (E- and F-Class). Figure 56 illustrates the changes in installed capacity to the Core scenario in GB, while Figure 57 shows minor adjustments in peaking and CCGT plants in the SEM market.

Figure 56 – Installed capacity by plant type in GB in Capacity payment scenario

Installed capacity in the Capacity payment and Core scenario

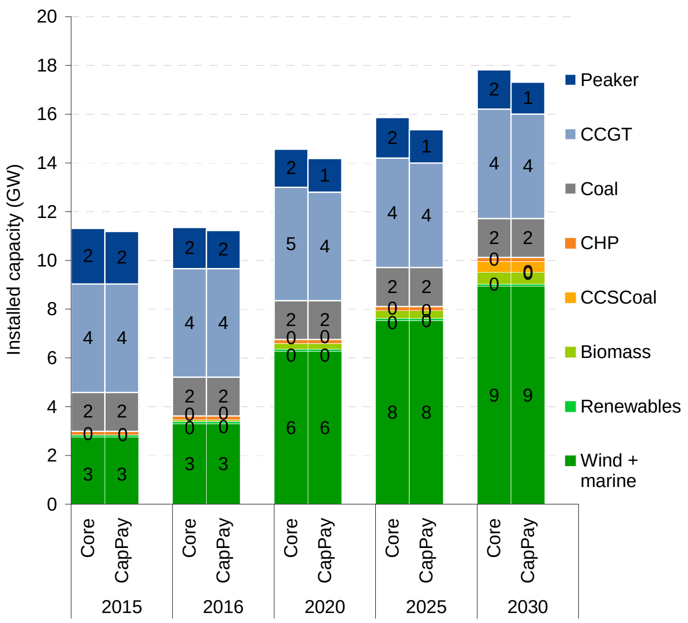


Changes in installed capacity in GW
(increase in blue, decrease in red)

in GW	2015	2016	2020	2025	2030
Wind + marine	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0
Wave	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0
Renewables	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0
CCSCoal	0.0	0.0	0.0	0.0	0.0
CHP	0.0	0.0	0.0	0.0	0.0
Coal	4.0	0.0	0.0	0.0	0.0
CCGT_E	0.0	0.0	2.4	2.4	0.0
CCGT_F	0.0	0.4	0.4	0.4	-1.2
Gas Steam	0.0	0.0	0.0	0.0	0.0
Old GT Gas	0.0	0.0	0.0	0.0	0.0
Old GT Gasoil	0.0	0.0	0.0	0.0	0.0
New GT Gasoil	0.3	1.3	1.3	1.3	3.3
Oil Steam	0.0	0.0	0.0	0.0	0.0

Figure 57 – Installed capacity by plant type in SEM in Capacity payment scenario

Installed capacity in the Capacity payment and Core scenario



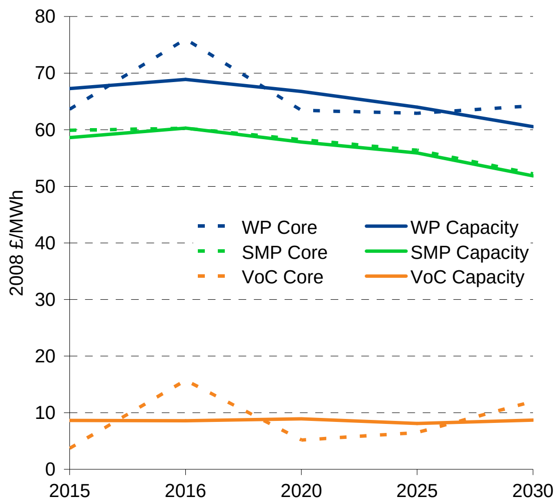
Changes in installed capacity in GW
(increase in blue, decrease in red)

in GW	2015	2016	2020	2025	2030
Wind + marine	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0
Wave	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0
Renewables	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0
CCSCoal	0.0	0.0	0.0	0.0	0.0
CHP	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0
CCGT	0.0	0.0	-0.2	-0.2	-0.2
Gas Steam	0.0	0.0	0.0	0.0	0.0
Advanced GT	0.0	0.0	-0.1	-0.1	-0.1
New GT Gas	-0.1	-0.1	0.0	-0.2	-0.2
New GT Gasoil	0.0	0.0	0.0	0.0	0.0
Oil Steam	0.0	0.0	0.0	0.0	0.0

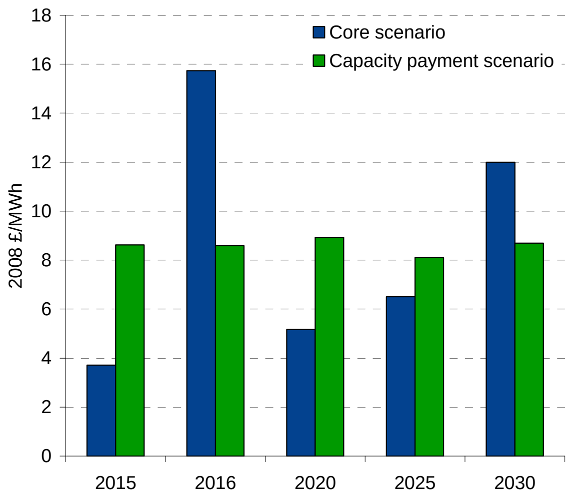
The impact of a CPM based on the SEM arrangements on the value of capacity element of prices is shown in Figure 58. It leads to much flatter and more stable prices and no peaks at times of system tightness (although we note that this may not fully reflect system fundamentals).

Figure 58 – Value of capacity in GB

SMP, VoC and wholesale price in Capacity Payment and Core Scenario



Value of capacity in Capacity Payment and Core Scenario



GB prices in Core Scenario

2008 £/MWh	SMP	VoC	Wholesale price
2015	59.9	3.7	63.6
2016	60.3	15.7	76.0
2020	58.3	5.2	63.4
2025	56.4	6.5	62.9
2030	52.2	12.0	64.2

GB prices in Capacity Payment Scenario

2008 £/MWh	SMP	VoC	Wholesale price
2015	58.6	8.6	67.3
2016	60.3	8.6	68.9
2020	57.8	8.9	66.8
2025	55.9	8.1	64.0
2030	51.9	8.7	60.5

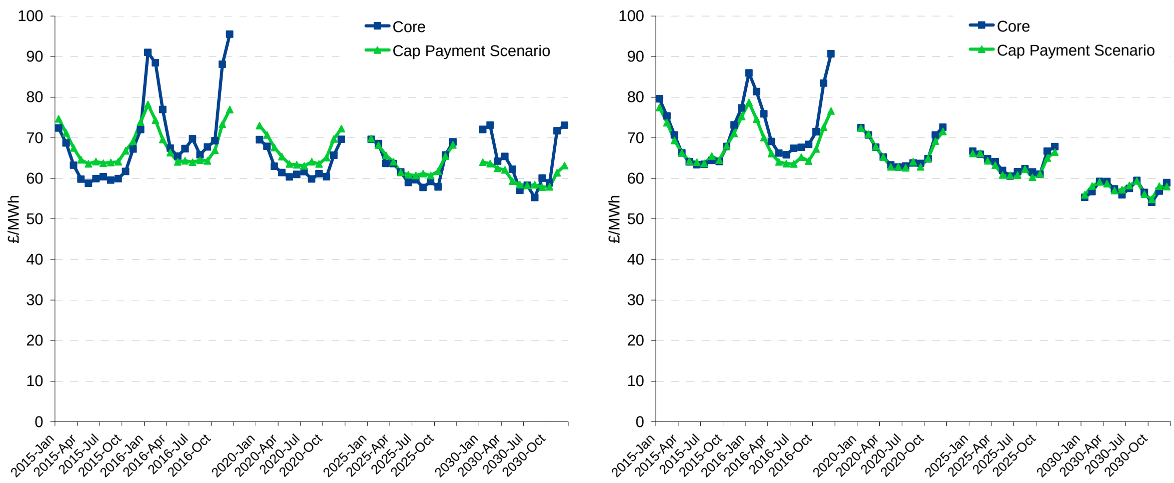
5.2.2 *Summary of impacts*

A shown in Figure 59, effects of the CPM are diverse: in 2016 and 2030 monthly wholesale prices are lower, whilst in other years they are higher than in the Core scenario. In all years price patterns are flatter as generators do not need to recover investment costs in a small number of years, but can be spread over a longer period. This outcome represents a much less risky market to operate in. Plant returns are less variable and less subject to the vagaries of the interaction between demand, availability and wind generation (which may be argued to be less reflective of market fundamentals).

Figure 59 – Monthly wholesale prices in GB and SEM in the Capacity Payment scenario

Monthly and annual wholesale prices in GB

Monthly and annual wholesale prices in SEM



GB (£/MWh)	2015	2016	2020	2025	2030
Core	63.6	76.0	63.4	62.9	64.2
Capacity payment	67.3	68.9	66.8	64.0	60.5
% Change	5.7%	-9.4%	5.3%	1.7%	-5.7%

SEM (£/MWh)	2015	2016	2020	2025	2030
Core	69.1	74.4	66.7	63.7	57.3
Capacity payment	68.6	68.9	66.4	63.1	57.5
% Change	-0.8%	-7.5%	-0.4%	-1.0%	0.5%

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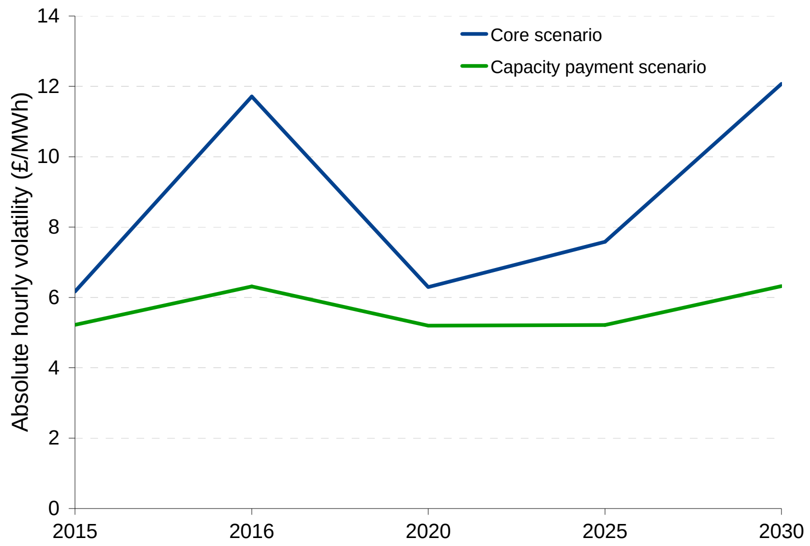
Having a capacity payment leads to slightly larger system margins due to the more stable returns that generators obtain. Given that building cheap and quick OCGTs is financially viable, these plant can be commissioned for any forecast shortfalls of capacity in a short time period both due to the simpler engineering and also the lower risk associated with lower capital costs. Also wholesale prices become less volatile in GB as the capacity payment mechanism prevents periods of very tight system margins and hence extremely high prices. Figure 60 shows the reduction in volatility with the adoption of a CPM, leading to volatility that halves in critical years such as 2016 and 2030. Due to the inter-linkage between the SEM and GB, a capacity mechanism in GB has a strong influence on the Irish market. In particular, the SEM no longer imports 'peaky' prices from GB, leading to Irish prices that are less volatile.

Figure 60 – Hourly price volatility in GB



The impact of CPM on IRRs is quite noticeable, as shown in Table 17. In GB, returns for OCGTs become much higher and compatible with new entry, whilst CCGT returns are driven downwards as prices are much lower on average. In the Irish market, returns for CCGTs reduce for the same reason and as a result no further CCGTs are built. As a result, Irish consumers would benefit from lower market prices in the SEM if GB adopted a capacity payment – however generators would lose revenue as they would no longer benefit from the stress that occurs in the GB market.

Table 17 – Internal Rate of Return in the Capacity payment scenario

IRRs in the Core scenario in GB

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.2%	11.6%	11.8%
CCSCoal	N/A	N/A	N/A	6.4%	6.5%	6.5%
Coal	N/A	N/A	3.6%	2.7%	3.4%	3.9%
CCGT_F	5.0%	7.6%	8.2%	6.2%	8.0%	9.4%
OCGT	<0	<0	<0	<0	<0	<0

IRRs in the Capacity Payment scenario in GB

	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	11.2%	11.1%	10.9%
CCSCoal	N/A	N/A	5.9%	5.2%	4.8%
Coal	N/A	2.5%	1.7%	1.1%	0.9%
CCGT_F	7.0%	6.8%	5.5%	4.8%	4.6%
OCGT	7.9%	7.9%	7.8%	7.8%	8.1%

IRRs in the Core scenario in the SEM

	2010	2015	2016	2020	2025	2030
CCGT	N/A	10.3%	10.4%	8.9%	8.3%	8.1%
CCSCoal	N/A	N/A	N/A	N/A	N/A	4.6%
Advanced GT	N/A	4.2%	5.3%	8.7%	8.7%	8.9%
OCGT (Gasoil)	11.8%	12.1%	12.2%	11.4%	11.4%	11.7%

IRRs in the Capacity Payment scenario in the SEM

	2015	2016	2020	2025	2030
CCGT	4.9%	4.7%	3.7%	3.2%	3.1%
CCSCoal	N/A	N/A	N/A	N/A	4.4%
Advanced GT	1.1%	2.0%	4.5%	4.6%	4.9%
OCGT (Gasoil)	8.1%	8.1%	8.1%	8.0%	8.3%

IRRs are pre-tax real over commercial lifetime of plant (see Figure 51 for detailed assumptions)

The impact of the Capacity Payment on overall end-user costs is detailed in Section 6.7.1. However, over the period 2015 to 2030, there is a very minor difference in end-user costs (covering the cost of buying electricity in the wholesale market) between the Core scenario and the Capacity Payment scenario, since flatter but higher prices in the Capacity Payment scenario are balanced by a few years of very high prices in the Core scenario.

5.3 Lower RES scenario

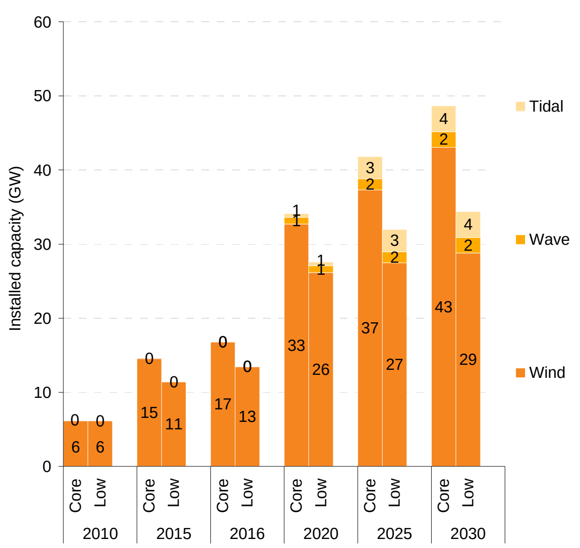
The Lower RES scenario investigates how a lower penetration of wind affects the results seen in the Core scenario.

5.3.1 *Changes compared to the Core scenario*

In the Lower RES scenario, we alter the volume of installed wind capacity as shown in Figure 61, reducing from 43GW to 29GW in 2030 in GB and from 8GW to 5GW in SEM.

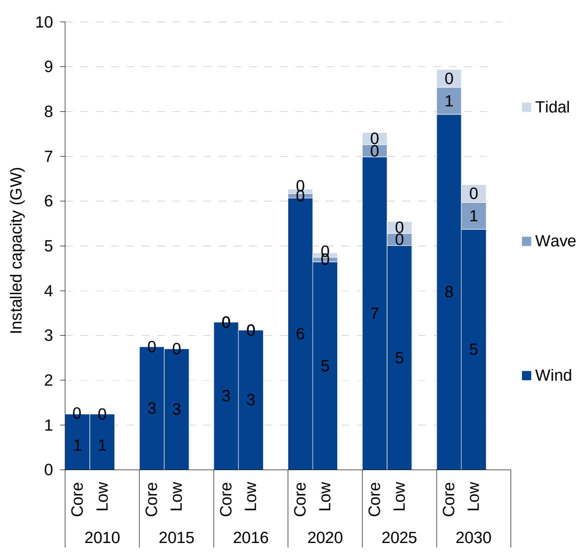
Figure 61 – Changes in wind capacity in GB and SEM

Installed wind, wave and tidal capacities in the Lower RES and Core scenario in GB



GB	2010	2015	2016	2020	2025	2030
Wind	0.0	-3.1	-3.3	-6.5	-9.8	-14.3
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0	0.0

Installed wind, wave and tidal capacities in the Lower RES and Core scenario in SEM

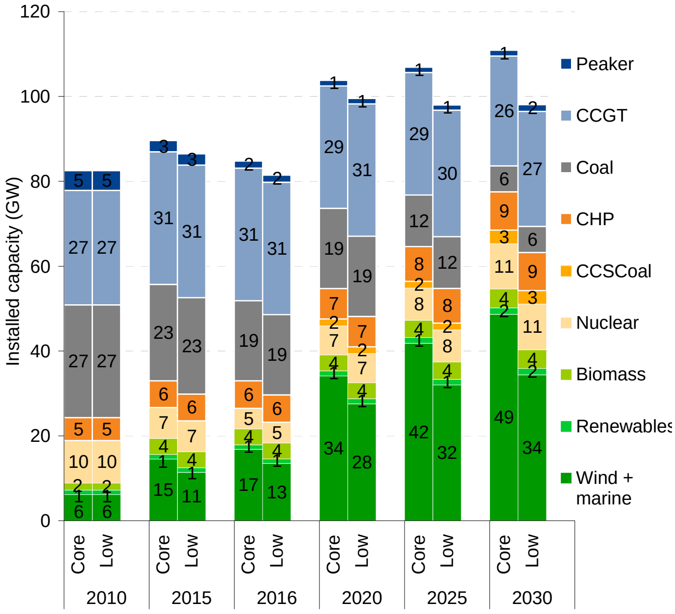


SEM	2010	2015	2016	2020	2025	2030
Wind	0.0	0.0	-0.2	-1.4	-2.0	-2.6
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0	0.0

Figure 62 illustrates the changes in total installed capacity in GB. Lowering the volume of wind means that E-class CCGTs are not forced to retire due to low returns, avoiding the need for additional new build until 2030.

Figure 62 – Installed capacity by plant type in GB in the Lower RES scenario

Installed capacity in the Lower RES and Core scenario



Changes in installed capacity
(increase in blue, decrease in red)

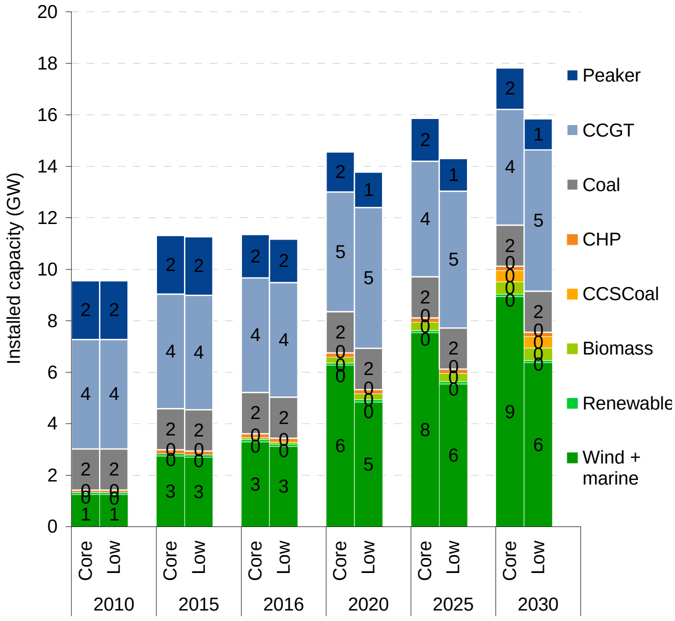
	2010	2015	2016	2020	2025	2030
Wind + marine	0.0	-3.1	-3.3	-6.5	-9.8	-14.3
Wind	0.0	-3.1	-3.3	-6.5	-9.8	-14.3
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
CCSCoal	0.0	0.0	0.0	0.0	0.0	0.0
CHP	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0
CCGT_E	0.0	0.0	0.0	2.3	1.0	0.0
CCGT_F	0.0	0.0	0.0	0.0	0.0	1.2
Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gas	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
New GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.2
Oil Steam	0.0	0.0	0.0	0.0	0.0	0.0

Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

Reducing installed wind capacities in Ireland also leads to less requirement for peaking generation, but additional need for CCGT new build (see Figure 63).

Figure 63 – Installed capacity by plant type in the SEM in the Lower RES scenario

Installed capacity in the Lower RES and Core scenario



Changes in installed capacity
(increase in blue, decrease in red)

	2010	2015	2016	2020	2025	2030
Wind + marine	0.0	0.0	-0.2	-1.4	-2.0	-2.6
Wind	0.0	0.0	-0.2	-1.4	-2.0	-2.6
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
CCSCoal	0.0	0.0	0.0	0.0	0.0	0.0
CHP	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	0.0	0.0	0.0	0.8	0.8	1.0
Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Advanced GT	0.0	0.0	0.0	0.0	0.0	0.0
New GT Gas	0.0	0.0	0.0	-0.1	-0.4	-0.4
New GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
Oil Steam	0.0	0.0	0.0	0.0	0.0	0.0

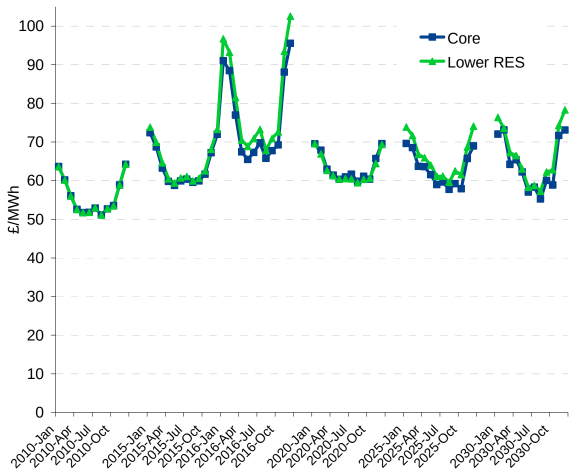
Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

5.3.2 Summary of impacts

The Lower RES scenario shows that with less wind deployed, monthly prices will have a stronger seasonal pattern as there is less downwards pressure from wind generation in the winter (see Figure 64). The seasonal price pattern does not reverse in Ireland as seen in the Core scenario, but only weakens from 2020 onwards. As expected, prices are less peaky than those in the Core scenario, and there are no zero or negative priced periods as wind generation does not exceed demand in any hour.

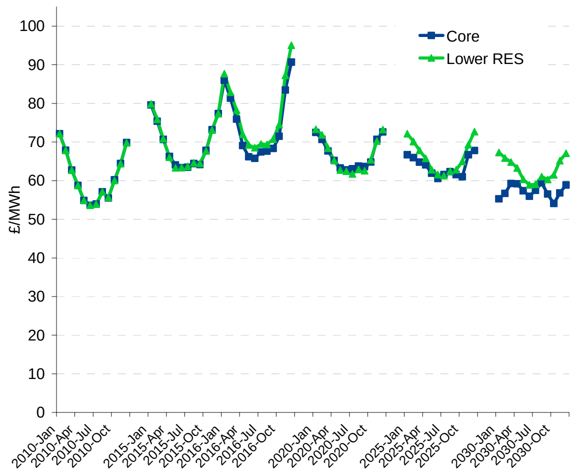
Figure 64 – Monthly wholesale prices in GB and SEM in the Lower RES scenario

Monthly and annual wholesale prices in GB



GB (£/MWh)	2010	2015	2016	2020	2025	2030
Core	55.8	63.6	76.0	63.4	62.9	64.2
Lower RES	55.8	64.5	80.1	63.0	65.9	66.5
% Change	0.0%	1.4%	5.4%	-0.7%	4.7%	3.6%

Monthly and annual wholesale prices in SEM



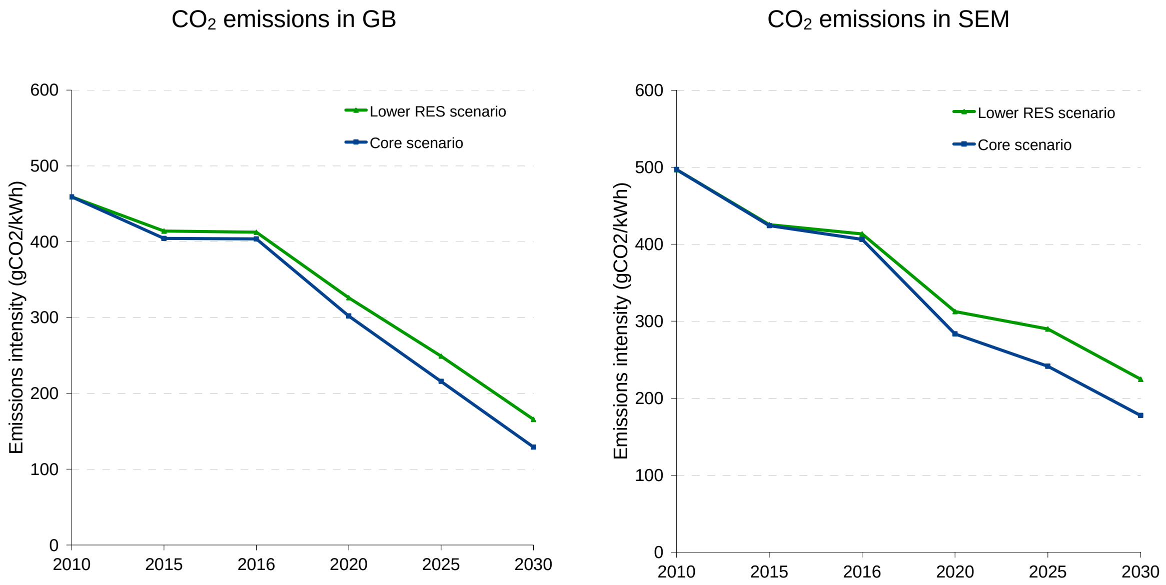
SEM (£/MWh)	2010	2015	2016	2020	2025	2030
Core	60.9	69.1	74.4	66.7	63.7	57.3
Lower RES	60.9	69.2	77.1	66.7	66.1	62.9
% Change	0.0%	0.1%	3.6%	-0.1%	3.8%	9.8%

With the assumed installed capacity, the renewable share of generation reaches 26% in the Lower RES scenario rather than 30% in the Core scenario in 2020 in GB, and 40% instead of 51% respectively in 2020 in SEM.

As fewer E-class CCGTs are forced to retire in GB and more CCGTs are built in SEM, emissions are significantly higher in 2030 in both markets. As shown in Figure 65, the emissions intensity drops in GB to only 165gCO_2/kWh in 2030, whilst in the SEM emissions remain above 200gCO_2/kWh.

Wind revenue cannibalisation drops in line with the lower installed wind capacity. This is discussed in more detail in Section 6.4.

Figure 65 – CO_2 emissions in GB and SEM in the Lower RES scenario



5.4 Carbon drop sensitivity

In the Carbon drop sensitivity the price of carbon has been reduced to £20/tCO_2 from £35/tCO_2 in the Core scenario. With a different coal-gas relativity; prices, load factors of coal and gas plants and emissions could be expected to change.

5.4.1 Changes compared to the Core scenario

The only input assumptions changed in this sensitivity is the price of carbon which has been reduced to £20/tCO_2 therefore decreasing the variable marginal costs of coal plants. Our fuel price assumptions including the new carbon price are shown in Table 18.

Table 18 – Fuel price assumptions in the Carbon drop sensitivity

in 2008 real money		2010	2015 onwards
Brent crude oil	$/bbl	66.0	70.0
Gas GB	p/therm	53.4	57.8
	£/MWh	18.2	19.7
Gas SEM	p/therm	57.1	61.5
	£/MWh	19.5	21.0
Coal (ARA CIF)	$/t	87.0	69.7
	£/MWh	8.1	6.7
Carbon	£/tonne CO2	20.0	20.0
	€/tonne CO2	21.4	21.6
Exchange rate	$per£	1.46	1.42
	€per£	1.07	1.08
GasOil (ARA CIF)	$/bbl	48.4	51.1
	£/MWh	33.8	36.6
LSFO (ARA CIF)	$/bbl	30.1	32.0
	£/MWh	18.3	20.0
Biomass	£/MWh	10.0	10.0

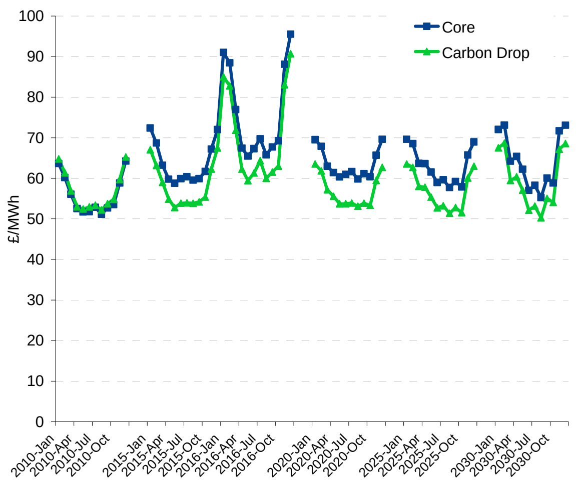
Note: All prices are at market pricing points. Gas is NBP for the GB market and the Irish Balancing Point for Ireland.

5.4.2 Summary of impacts

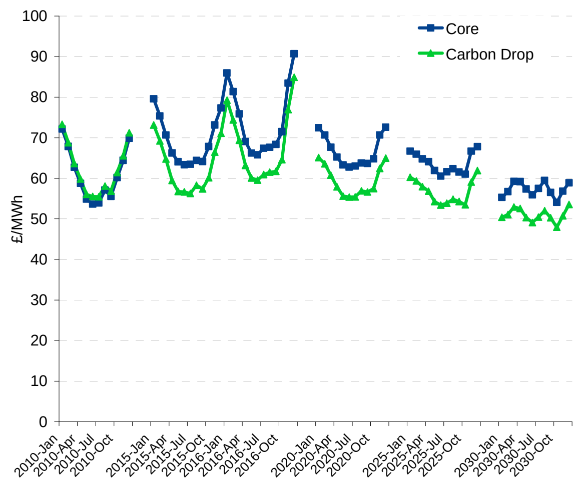
With a carbon price that is £15/tCO_2 lower than in the Core scenario, wholesale prices drop substantially – by an average of 9% in GB and 10% in SEM (see Figure 66). This is mainly due to the reduction in the variable costs of generation with a lower carbon price. Overall monthly price patterns are unaffected since these are driven by system tightness, gas price seasonality and wind generation – all of which stay the same between the two scenarios.

Figure 66 – Monthly wholesale prices in GB and SEM in the Carbon drop sensitivity

Monthly and annual wholesale prices in GB



Monthly and annual wholesale prices in SEM

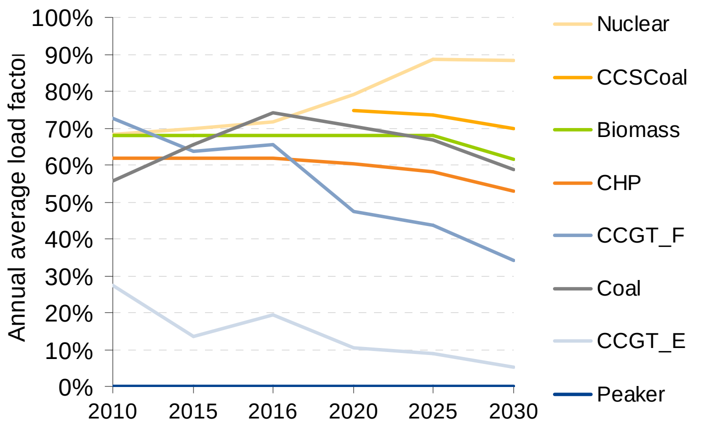


GB (£/MWh)	2010	2015	2016	2020	2025	2030
Core	55.8	63.6	76.0	63.4	62.9	64.2
Carbon Drop	56.7	58.1	70.4	56.8	56.8	59.4
% Change	1.7%	-8.6%	-7.4%	-10.4%	-9.7%	-7.5%

SEM (£/MWh)	2010	2015	2016	2020	2025	2030
Core	60.9	69.1	74.4	66.7	63.7	57.3
Carbon Drop	62.1	62.4	68.0	59.3	56.6	51.0
% Change	2.0%	-9.6%	-8.6%	-11.1%	-11.2%	-11.0%

In the GB market the lower carbon price significantly increases load factors of coal plant and depresses F-class CCGTs. As illustrated in Figure 67, neither nuclear nor peaking plant load factors are affected. Load factors of CCS coal plant decrease only slightly and are still above 70% in 2030.

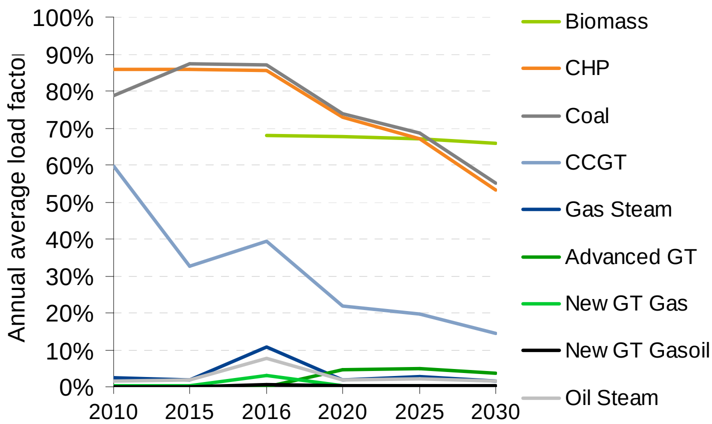
Figure 67 – Plant load factors in GB in the Carbon drop sensitivity



%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	61%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	60%	58%	53%
CCGT_E	27%	14%	19%	10%	9%	5%
CCGT_F	73%	64%	66%	47%	44%	34%
Coal	56%	65%	74%	70%	67%	59%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

As shown in Figure 68, a similar development occurs in the SEM: load factors of coal plant increase substantially while CCGTs load factors drop to 20% in 2020. New Advanced GT plants perform slightly better than other peaking plants in SEM, but do not exceed a load factor of 5%.

Figure 68 – Plant load factors in the SEM in the Carbon drop sensitivity



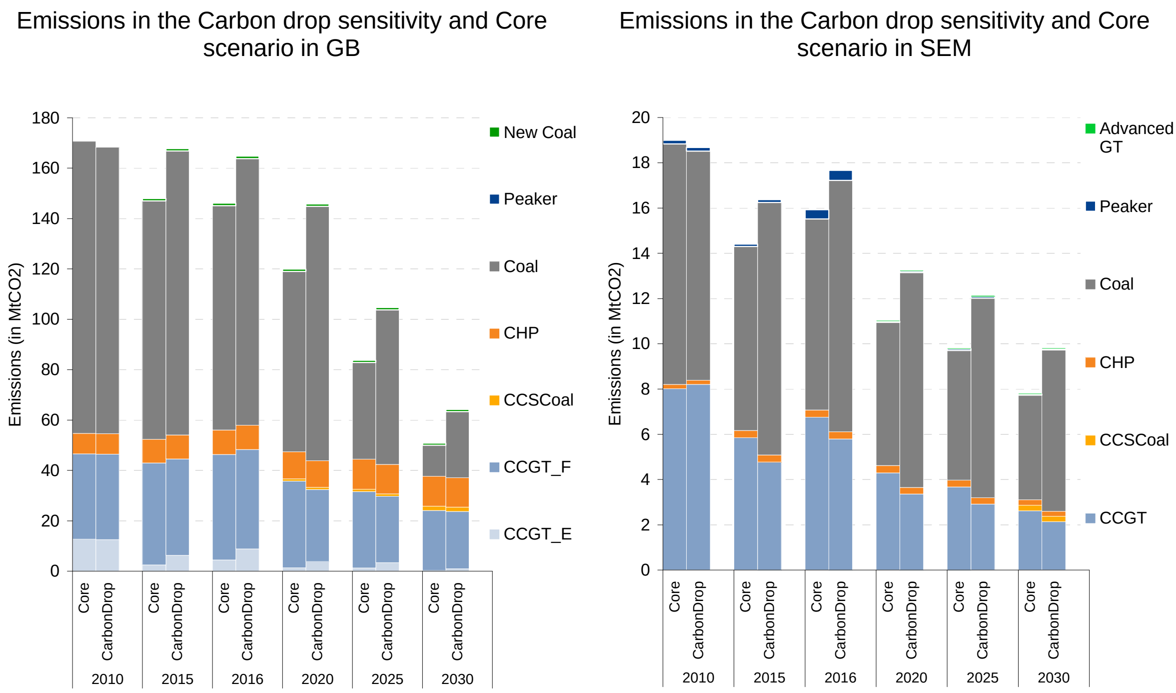
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						70%
CHP	86%	86%	86%	73%	67%	53%
Coal	79%	88%	87%	74%	69%	55%
CCGT	60%	33%	39%	22%	20%	14%
Gas Steam	3%	2%	11%	2%	3%	2%
Advanced GT	<0.1%	<0.1%	<0.1%	4.5%	5.0%	3.7%
New GT Gas	0.2%	0.2%	3.0%	0.3%	0.2%	0.1%
New GT Gasoil	<0.1%	<0.1%	0.6%	0.2%	0.3%	0.3%
Oil Steam	1.5%	1.7%	7.7%	1.9%	2.3%	1.7%

For plant returns, IRRs of coal plant rise due to lower carbon costs, and those of CCGTs drop slightly in GB as coal generates more. In the SEM, the CPM keeps peaking plant profitable. IRRs are covered in Section 6.3.

The effects of a lower CO_2 price and resulting higher coal generation are shown in Figure 69. Overall, emissions are 10-20% higher with a carbon price £15/tCO_2 below that in the

Core scenario. The higher share of coal generation significantly increases emissions in GB and SEM from 2015 onwards. In the SEM this increase keeps steady until 2030, while there is a little reduction in GB.

Figure 69 – CO_2 emissions in GB and SEM in the Carbon drop scenario



5.5 IED (Industrial Emissions Directive) scenario

The IED scenario assumes a strict implementation of the Industrial Emissions Directive and analyses the resulting requirements for new build. Applying the proposed legislation, 5GW of coal and 8GW of CCGTs are forced to close in 2020. To assess the impacts of the IED, plant closures, new build requirements, effects on wholesale prices and implications for system cost are investigated.

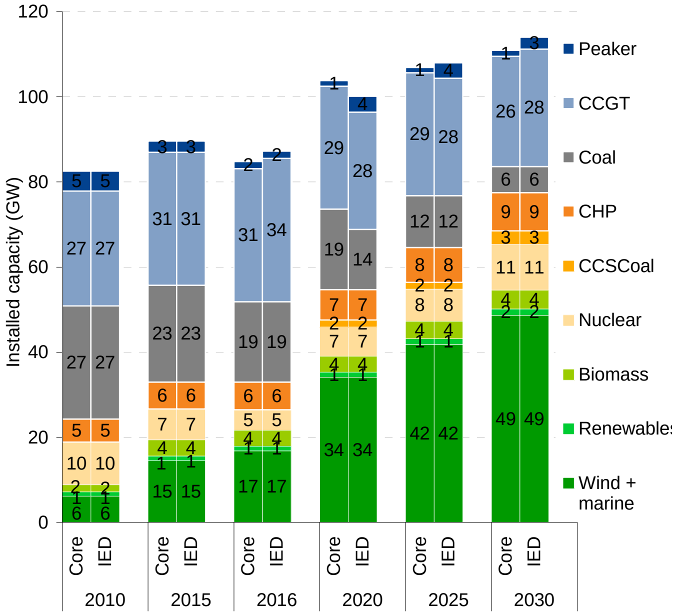
5.5.1 Changes compared to the Core scenario

The IED has a potentially significant effect on plants in GB. In particular, about 5GW of coal and 8GW of CCGT have to close in 2020. Those capacities are in addition to plants shut down in 2016 due to the LCPD. Figure 70 illustrates the difference between the Core and IED scenarios. Only building new CCGTs would displace other CCGTs, leading to depressed infra-marginal rents for all plant – hence some OCGTs are required to maintain prices. We therefore assume nearly 7GW of new build CCGTs and over 2GW of OCGTs to ensure sufficient returns of older CCGTs.

There are no changes in installed capacity in SEM due to the IED, as plant either have FGD fitted or (for CCGTs) are new enough not to be affected.

Figure 70 – Installed capacity by plant type in GB in the IED scenario

Installed capacity in the IED and Core scenario in GB



Changes in installed capacity
(increase in blue, decrease in red)

	2010	2015	2016	2020	2025	2030
Wind + marine	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	0.0	0.0
Renewables	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
CCSCoal	0.0	0.0	0.0	0.0	0.0	0.0
CHP	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	-4.8	0.0	0.0
CCGT_E	0.0	0.0	0.0	-8.1	-8.1	-3.1
CCGT_F	0.0	0.0	2.4	6.8	6.8	4.8
Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gas	0.0	0.0	0.0	0.0	0.0	0.0
Old GT Gasoil	0.0	0.0	0.0	0.0	0.0	0.0
New GT Gasoil	0.0	0.0	0.0	2.4	2.4	1.4
Oil Steam	0.0	0.0	0.0	0.0	0.0	0.0

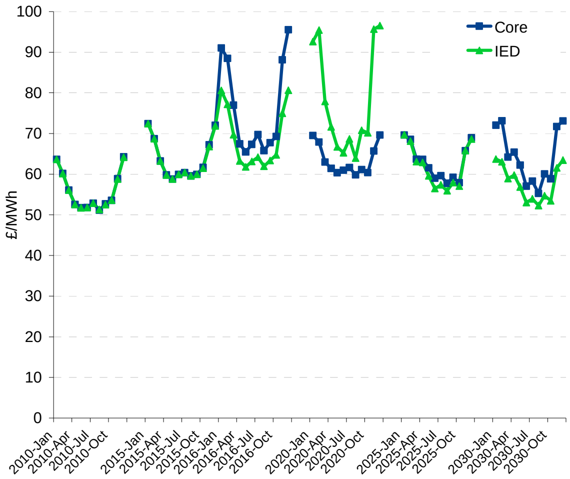
Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

5.5.2 *Summary of impacts*

The effect on monthly wholesale prices in GB and SEM can be seen in Figure 71. Due to additional new build CCGTs in early years, prices in GB are less spiky in 2016, but increase dramatically in 2020 due to IED plant retirals. Prices in SEM are driven up in 2020 as well, though to a lesser extent.

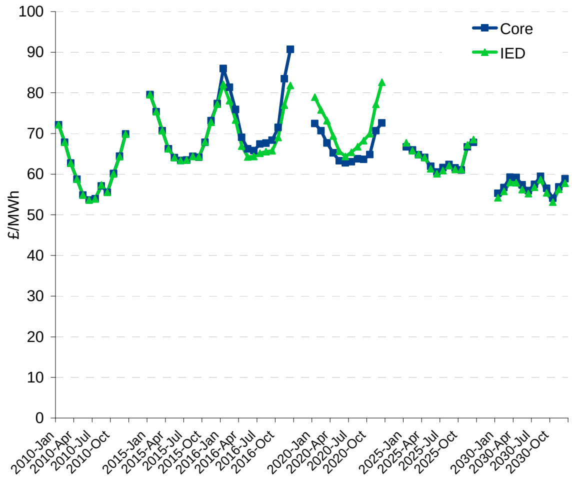
Figure 71 – Monthly wholesale prices in GB and SEM in the IED scenario

Monthly and annual wholesale prices in GB



GB (£/MWh)	2010	2015	2016	2020	2025	2030
Core	55.8	63.6	76.0	63.4	62.9	64.2
IED	55.8	63.6	68.7	77.8	61.8	57.9
% Change	0.0%	-0.1%	-9.5%	22.7%	-1.7%	-9.9%

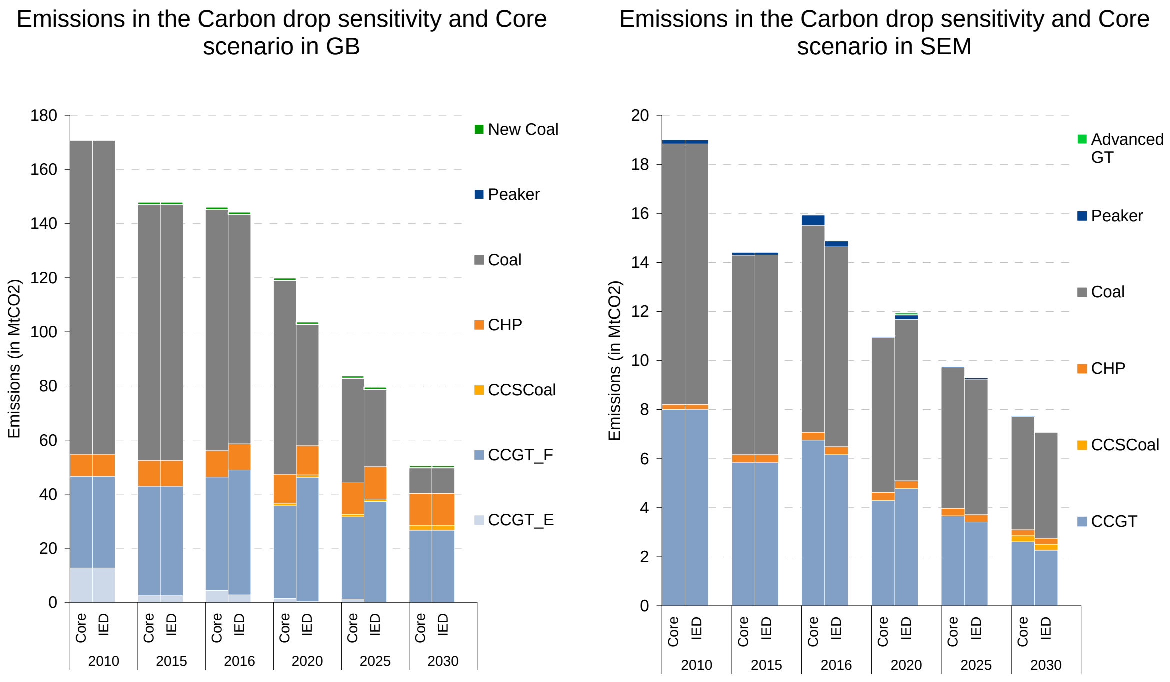
Monthly and annual wholesale prices in SEM



SEM (£/MWh)	2010	2015	2016	2020	2025	2030
Core	60.9	69.1	74.4	66.7	63.7	57.3
IED	60.9	69.1	71.1	71.4	63.7	56.3
% Change	0.0%	0.0%	-4.5%	7.1%	0.0%	-1.7%

The closure of old GB plant reduces emissions by almost 20MtCO_2 in 2020. Given that much of this plant would have closed in 2025 anyway, reductions after 2025 are much smaller and negligible in 2030. Emissions in the SEM increase in 2016 as a result of the plant closures in GB and the resulting larger generation of Irish plant which leads to higher exports from the SEM to the GB market.

Figure 72 – CO_2 emissions in GB and SEM in the IED scenario



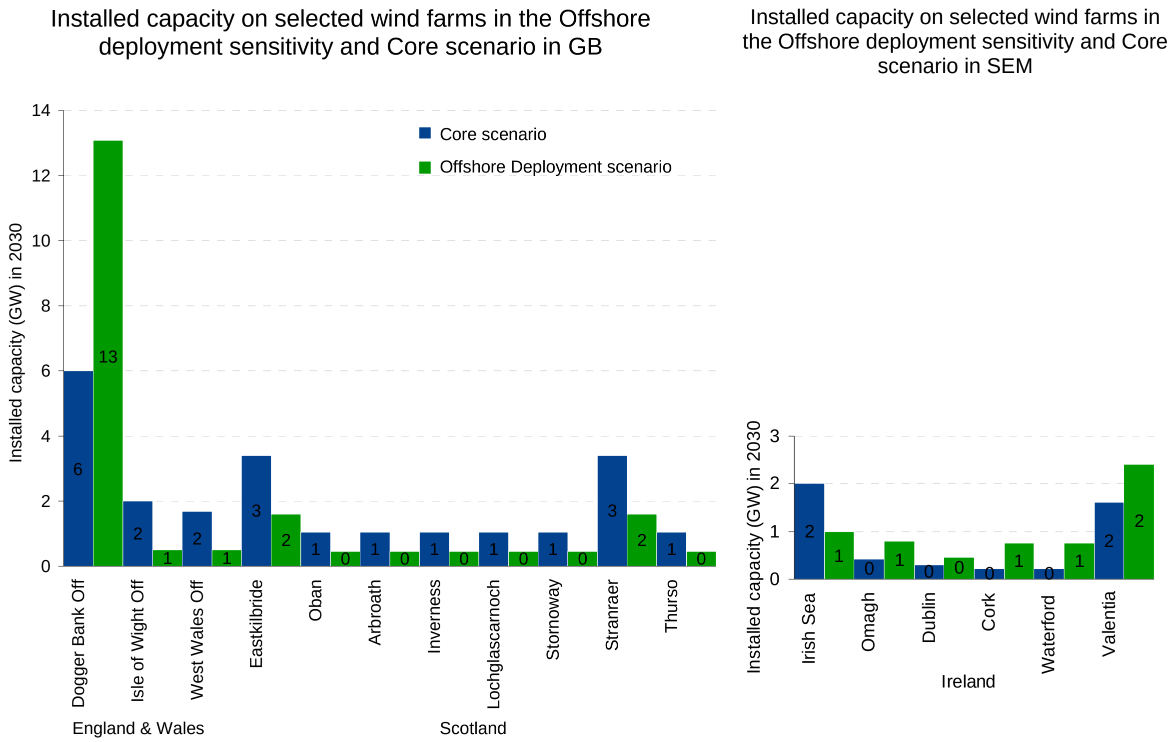
5.6 Offshore deployment sensitivity

The Offshore deployment sensitivity investigates how geographically concentrated wind build with significant deployment on the Dogger Bank affects wholesale prices, spreads and price volatility in both markets.

5.6.1 Changes compared to the Core scenario

To increase wind deployment on the Dogger Bank, energy from wind is assumed to equal the Core scenario in 2020 and 2030, however installed capacities are shifted from Scotland and England & Wales to the Dogger Bank. As shown in Figure 73, the capacity installed on the Dogger Bank increases from 6GW to 13GW.

Figure 73 – Changes to installed wind capacity in 2030 in the Offshore deployment sensitivity

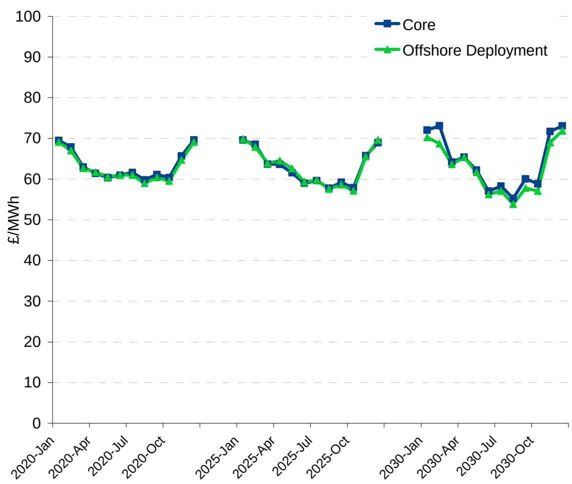


5.6.2 *Summary of impacts*

By 2030, despite the same volume of wind generation, wholesale prices are slightly higher as wind is more correlated throughout the GB market and hence periods of tight system margins becoming more frequent (see Figure 74).

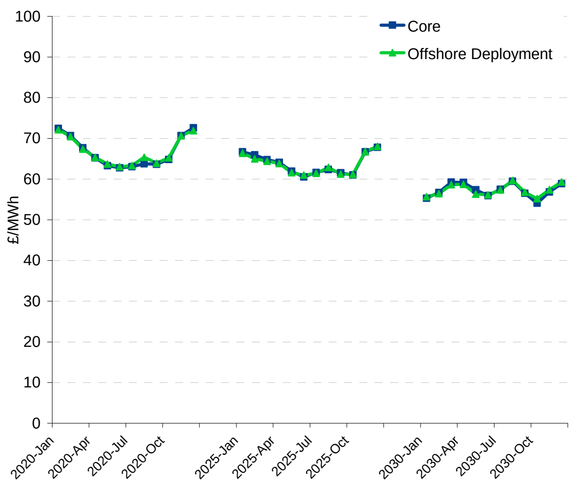
Figure 74 – Monthly wholesale prices in GB and SEM in the Offshore deployment sensitivity

Monthly and annual wholesale prices in GB



GB (£/MWh)	2020	2025	2030
Core	63.4	62.9	64.2
Offshore Deployment	64.0	63.9	63.5
% Change	0%	0%	1%

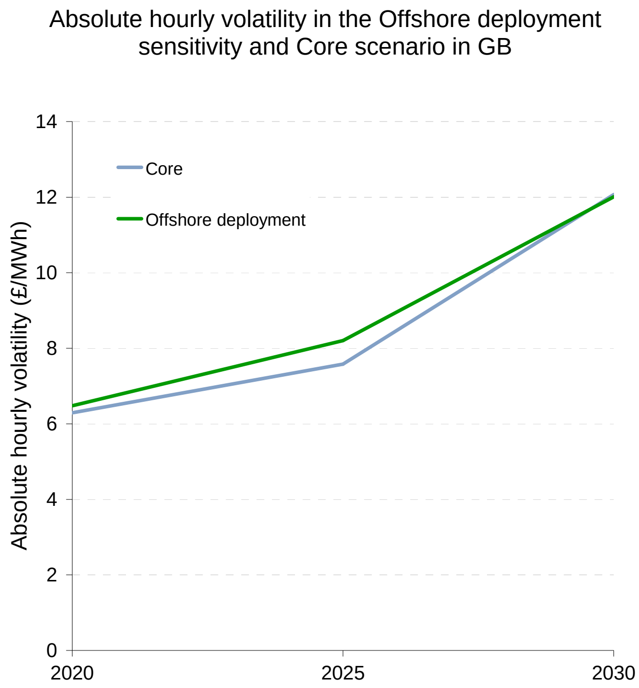
Monthly and annual wholesale prices in SEM



SEM (£/MWh)	2020	2025	2030
Core	66.7	63.7	57.3
Offshore Deployment	66.9	63.8	57.6
% Change	-1.0%	-3.6%	-4.5%

Despite more wind generation together in the North Sea and the higher correlation this implies, there is no significant increase in price volatility, as shown in Figure 75. In part this is because the increasing volumes of wind generation offshore have been accompanied by a decrease in capacity elsewhere, and in addition the decreased capacity was already correlated to some extent with the offshore wind – somewhat correlated wind generation has been replaced with highly correlated wind generation. However, there is an impact on the capture price of wind, with wind revenue for offshore sites decreasing due to the increased correlation of wind generation. These impacts of clustering installed capacity on wind revenue are discussed in section 6.4.1.

Figure 75 – Price volatility in the Offshore deployment sensitivity



5.7 Severn barrage sensitivity

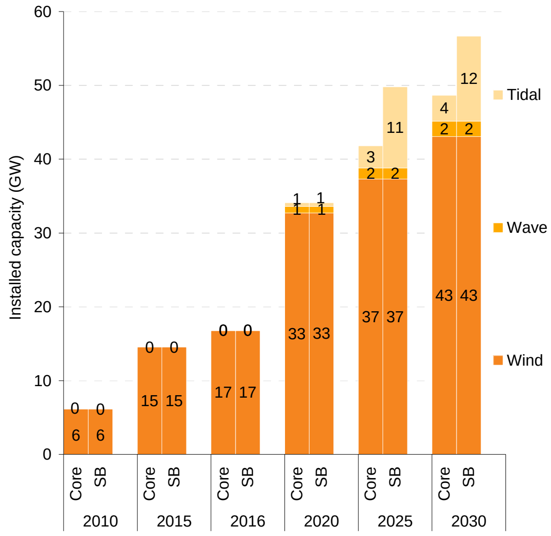
The Severn barrage sensitivity is deploying a 10GW barrage in England & Wales and analyses the effects on wholesale prices, plant ramping, wind output and emissions.

5.7.1 Changes compared to the Core scenario

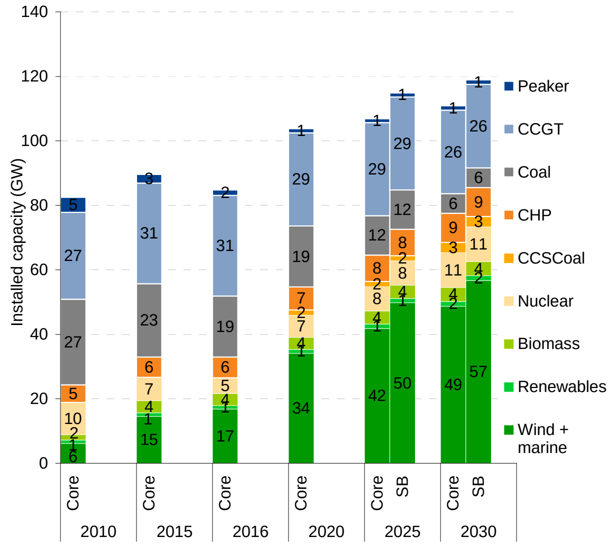
Instead of the 2GW of Shoots-type barrage in the Core scenario, this sensitivity is run with a single 10GW Cardiff-Weston barrage. The total installed capacity in the GB market is illustrated in Figure 76.

Figure 76 – Installed capacity by plant type in GB in the Severn barrage sensitivity

Installed wind, wave and tidal capacity in Severn barrage sensitivity and Core scenario



Total installed capacity in Severn barrage sensitivity and Core scenario



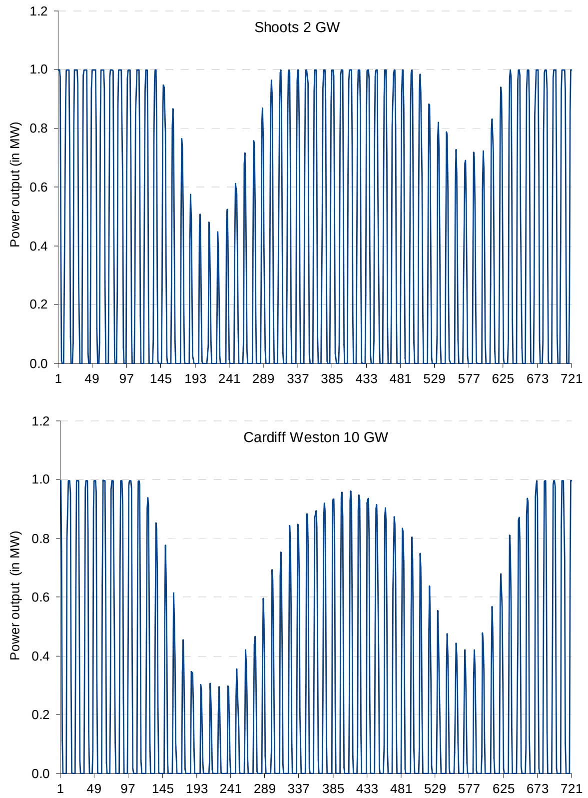
GB	2010	2015	2016	2020	2025	2030
Wind	0.0	0.0	0.0	0.0	0.0	0.0
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Tidal	0.0	0.0	0.0	0.0	8.0	8.0

Note: The charted category 'Peaker' includes gas and oil steam as well as new and old GT plants.

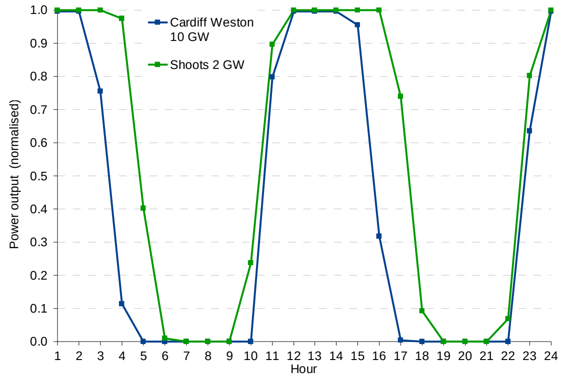
The profile for the 10GW Cardiff-Weston barrage is different to the 2GW Shoots barrage profile (see Figure 77). While the first one is more volatile and does not reach its maximum generation in neap tide periods, the latter generates maximum outputs in over half of the time. However, the larger barrage has a profile that has more periods of zero output. This is critical, as it means that system security is *reduced* compared to a smaller barrage, as the amount of time with no generation is increased.

Figure 77 – Tidal profiles in the Severn barrage sensitivity

Monthly tidal profiles – Shoots 2 GW and Cardiff-Weston 10GW



Daily tidal profiles – Shoots 2 GW and Cardiff-Weston 10GW



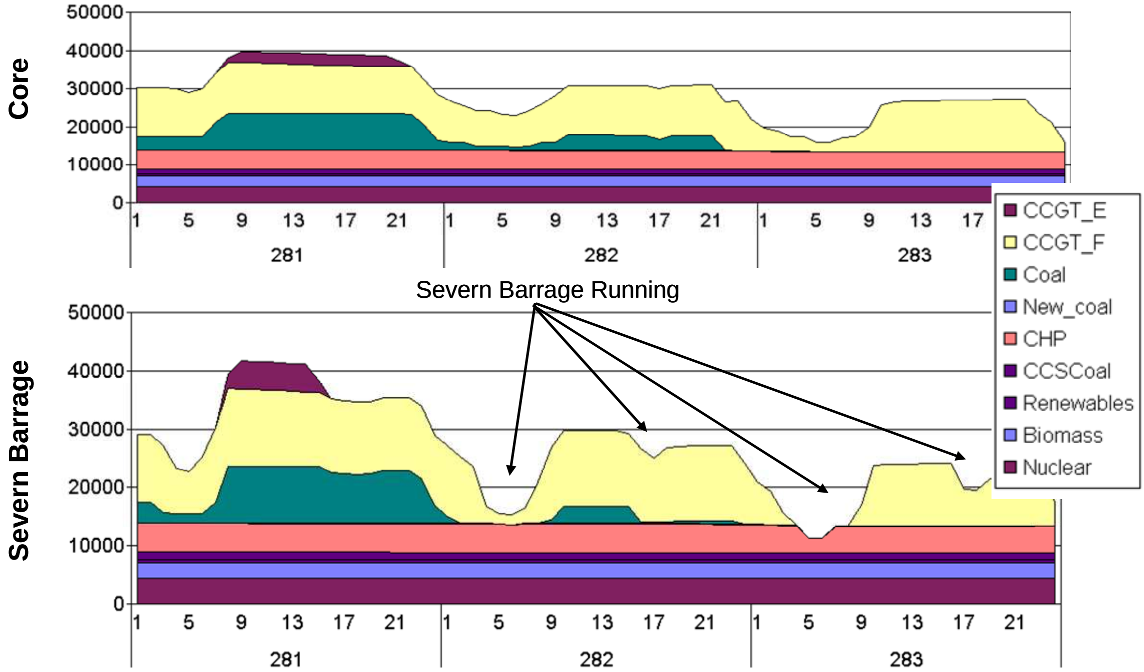
Note: tidal profiles are unitised (scaled to 1).

5.7.2 *Summary of impacts*

Average annual and monthly prices are only negligibly affected by a large tidal generation in 2025 and 2030. GB prices drop by about 2% in 2030; SEM prices by 2.8%. However, the Severn barrage significantly increases price volatility in GB, having the highest volatility of all presented scenarios. Price volatility is almost 50% greater than in the Core Scenario (as detailed in 6.1.2).

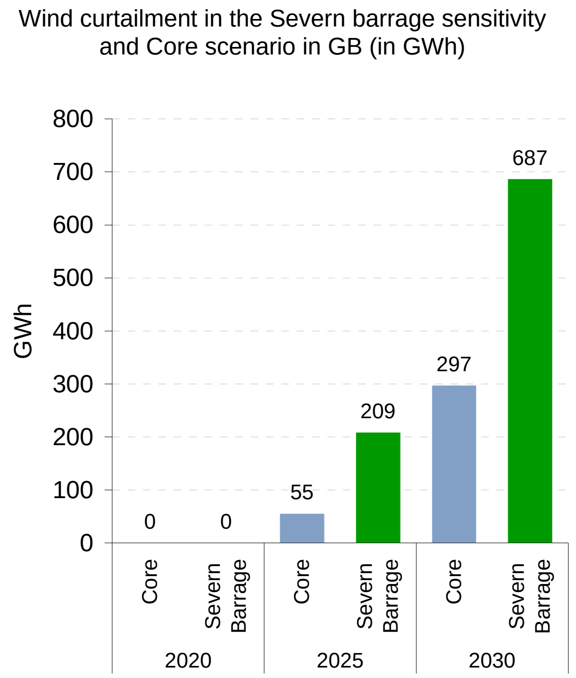
The Severn barrage has a noticeable effect on thermal plant operation, as shown in Figure 78 for Monte Carlo 2004 in 2025. Tidal generation depresses thermal plants running by a maximum of twice a day.

Figure 78 – Plant operation in GB in the Severn barrage sensitivity



The Severn barrage scenario results in the lowest emissions of all presented scenarios, dropping to under 50MtCO_2 in 2030 in GB, with the emissions intensity falling to 116gCO_2/kWh. A large Severn barrage increases the numbers of periods when wind is being curtailed due to excessive generation on the system. Wind loss periods significantly grow from 56 to 138 periods in 2020 in GB and 200 to 341 periods in 2030.

Figure 79 – Wind curtailment and periods of wind loss in the Severn Barrage sensitivity



Wind loss periods	2010	2015	2016	2020	2025	2030
Core Scenario	0	0	0	0	55	198
Severn Barrage Scenario	n/a	n/a	n/a	n/a	138	341

5.8 Interconnection sensitivity

The Interconnection sensitivity investigates the impact of a smaller interconnection between GB and Ireland on prices in GB and SEM, interconnector flows and wind output.

5.8.1 Changes compared to the Core scenario

The current Moyle interconnection between Scotland and Northern Ireland is 400MW (tradable) export from Scotland and 80MW import. In the Core scenario, we have assumed this is expanded, so as a sensitivity in the Interconnection case, this is assumed to remain at its current values – a reduction in export capacity from Ireland (see Table 19). The new build connection between England & Wales and the Republic of Ireland will come online in the same year, but with half the capacity assumed in the Core scenario.

Table 19 – Changes to interconnector capacity between GB and SEM

Scenario	From	To	2010	2015	2016	2025	2030
Core	E&W	RI	0.0	1.0	1.0	1.0	1.0
Core	SC	NI	0.4	0.4	0.4	0.4	0.4
Intercon	E&W	RI	0.0	0.5	0.5	0.5	0.5
Intercon	SC	NI	0.4 / 0.08	0.4 / 0.08	0.4 / 0.08	0.4 / 0.08	0.4 / 0.08

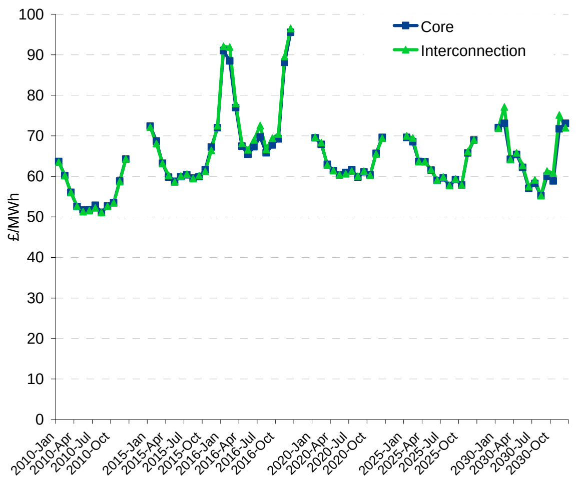
Note: If not indicated in the table, all capacities have been assumed to be identical in each direction.

5.8.2 Summary of impacts

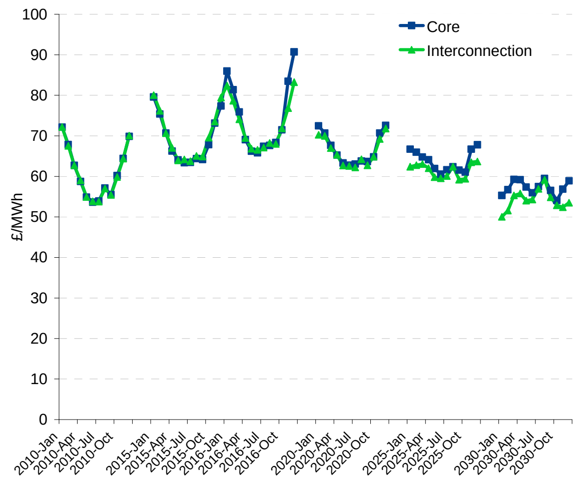
The impact of changing interconnection on prices is negligible in GB as shown in Figure 80. In SEM however, monthly and annual prices fall in 2025 and 2030 as a result of 'stranded wind'.

Figure 80 – Monthly wholesale prices in GB and SEM in the Interconnection sensitivity

Monthly and annual wholesale prices in GB



Monthly and annual wholesale prices in SEM



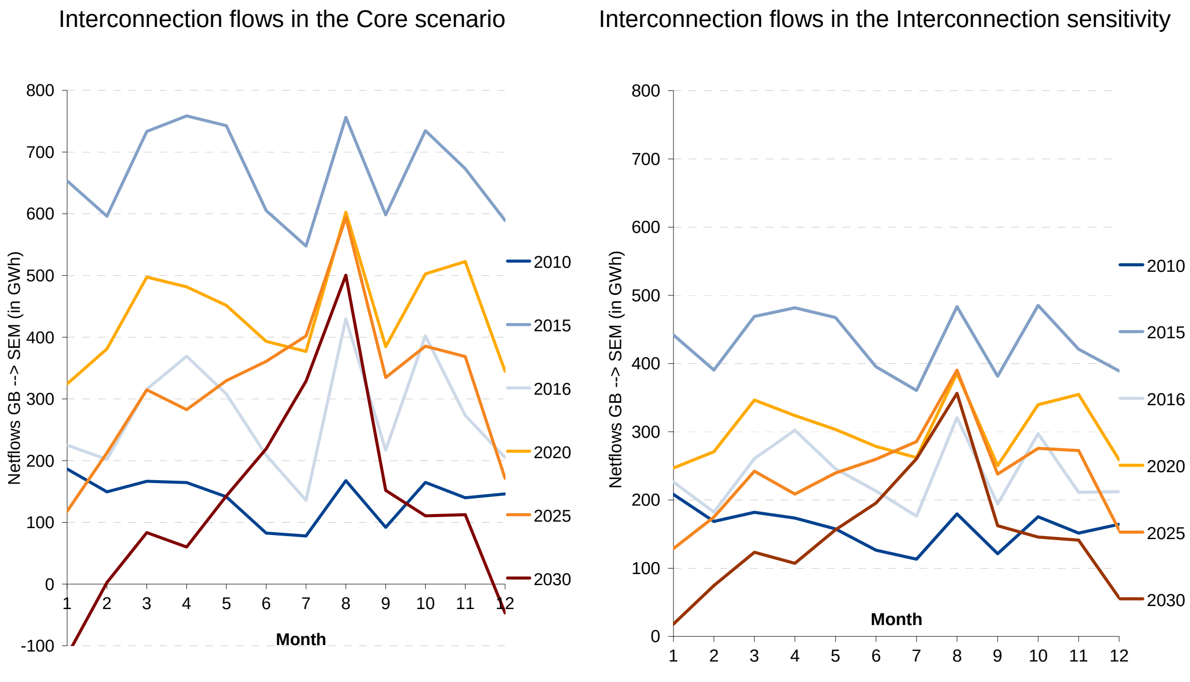
GB (£/MWh)	2010	2015	2016	2020	2025	2030
Core	55.8	63.6	76.0	63.4	62.9	64.2
Interconnection	55.6	63.5	77.5	63.4	63.1	65.1
% Change	-0.2%	-0.1%	1.9%	-0.1%	0.3%	1.5%

SEM (£/MWh)	2010	2015	2016	2020	2025	2030
Core	60.9	69.1	74.4	66.7	63.7	57.3
Interconnection	60.9	69.8	72.8	66.1	61.5	54.2
% Change	0.0%	1.0%	-2.2%	-1.0%	-3.6%	-5.3%

,

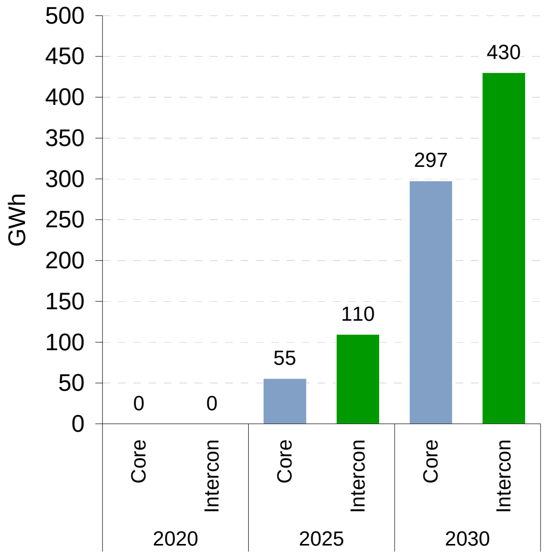
Figure 81 illustrates monthly net interconnector flows from the GB market to the SEM. Overall flows are much lower in all years, but the general patterns remain very similar with a move towards more exports from Ireland in winter months by 2030. Interconnectors are constrained much of the time between the two countries – this is discussed more in Section 6.6.1.

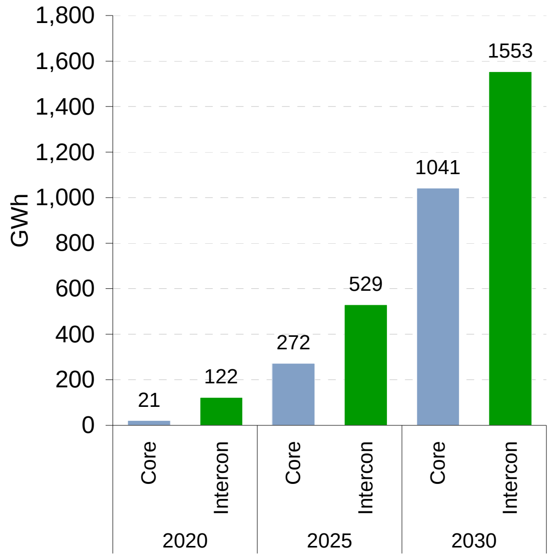
Figure 81 – Interconnector flows in the Interconnection sensitivity



Smaller interconnection pushes down returns for SEM plant across all class of plant, as the market becomes less interconnected to high GB prices in 2015-20 and excess wind cannot be exported from 2020. Carbon emissions also rise in the SEM from 11MtCO_2 to 12MtCO_2 in 2020. This is due to lower imports from the UK and more de-loaded wind which both require Irish thermal plant to run more.

Figure 82 – Wind curtailment and periods of wind loss in the Interconnection sensitivity





Wind loss periods	2010	2015	2016	2020	2025	2030
Core Scenario	0	0	0	0	55	198
Intercon Scenario	0	0	0	0	121	295

Wind loss periods	2010	2015	2016	2020	2025	2030
Core Scenario	0	0	0	61	264	723
Intercon Scenario	0	0	0	222	587	1177

Due to reduced exports of excessive Irish wind to the GB market and to a lesser extent the other way around, wind curtailment increases in both countries, as shown in Figure 82. Especially in Ireland, periods of wind loss raise from 61 to 222 in 2020 and 723 to 1177 in 2030.

5.9 Demand side management scenarios

The ability to flatten demand during the day offers significant potential to reduce system costs and create a more economically and better designed electricity system. Currently, demand for electricity is largely (if not wholly) independent of the cost in any hour to produce it. As a result, consumers' behaviour is not influenced by the cost of producing electricity in any meaningful manner. By reducing peak demand, savings may be possible through reducing new build of generation, and minimising the number of starts of plant. Also, if demand is more dynamic, it may be possible to offset some of the intermittent effects from wind by increasing demand at times of high wind generation, and decreasing it when there is less wind.

This study has examined two cases where demand side management is implemented – inflexible demand management and price responsive demand management. The uncertainty surrounding demand side management is significant, and so the scenarios represent an illustration of the impact, rather than a definitive view of how demand side management may contribute.

- **Case 1: Inflexible demand management ('dumb meters').** This assumes that demand is moved from the peaks during the day to the troughs during the night. This is achieved by a similar system to the Economy 7 heating system in the UK or Night Saver used in the ROI, with demand for space and water heating primarily moving. Additionally, we have added electric vehicles, assuming overnight charging.

- **Case 2: Price responsive demand management ('smart meters')**. This assumes that load can be dynamically moved from when required to when it is cheapest, using smart meters that receive information about wholesale prices and reschedule energy demand accordingly. In effect, load can act as electricity storage, allowing consumers to change the timing of electricity demand (primarily water and space heating) to minimise their costs.

The Appendices contain a more detailed discussion on the scope for demand management, and on our underlying assumptions.

5.9.1 Inflexible demand management assumptions

For the Inflexible Demand Management scenario, we have changed the underlying demand profile by adding an additional heating profile and an electric car profile. This represents heating demand (both space and water) that takes places overnight rather than during the day. In both GB and Ireland the heating profile has been taken from the existing Economy 7 profile.

It is more difficult creating a reasonable assumption for electric vehicles, as very few of these exist and the technology may undergo significant changes from the status quo before deployment. Thus we have assumed that the profile of charging of electric vehicles is the inverse of the diurnal pattern of use of electric vehicles.

For this scenario, we have assumed that the total annual demand remains identical to the Core scenario – in effect any increase in space or water heating and electric vehicles is offset by greater increases in energy efficiency compared to our Core scenario. This allows a direct comparison of how the system may behave without significantly changing the underlying assumptions on build requirements.

The resulting profile for England and Wales is shown in Figure 83, showing that energy consumption at the peaks is reduced, with a corresponding increase in demand during the early hours of the morning.

It should be noted that resulting profile becomes doubled peaked – at least in winter. This is due to the lack of smoothing in an inflexible demand management system, where load is determined by the time of day rather than wholesale prices. In reality, we may expect a smoother profile than this – as a combination of inflexible and price responsive or smart demand management is implemented.

Figure 83 – Demand profile in GB for Core and Inflexible Demand scenarios

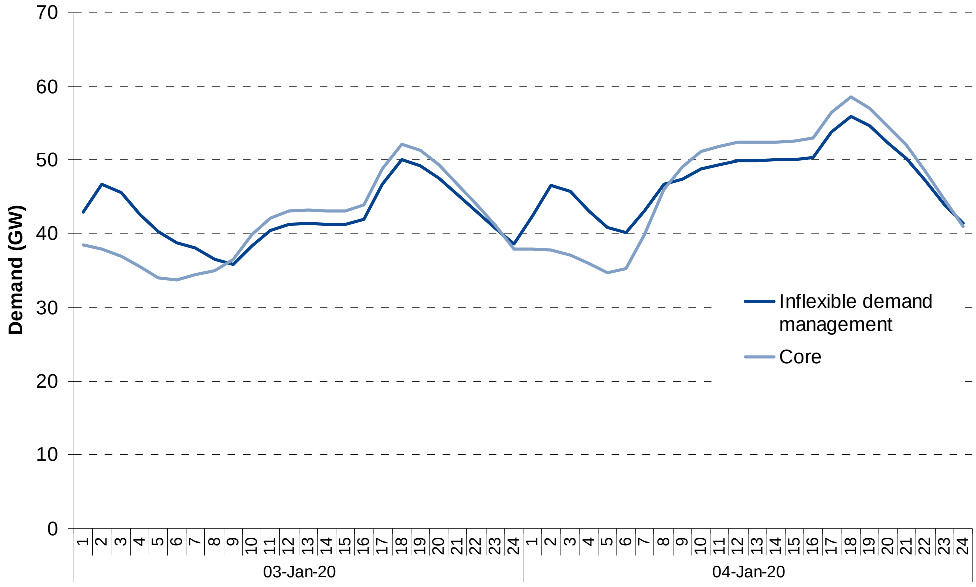


Figure 84 shows the demand duration curve for 2020 for GB and the SEM. In both markets, peak demand is reduced, whilst energy is shifted from higher demand hours to those with lower demand.

Figure 84 – Demand duration curve in GB and SEM in Core and Inflexible Demand Management scenario

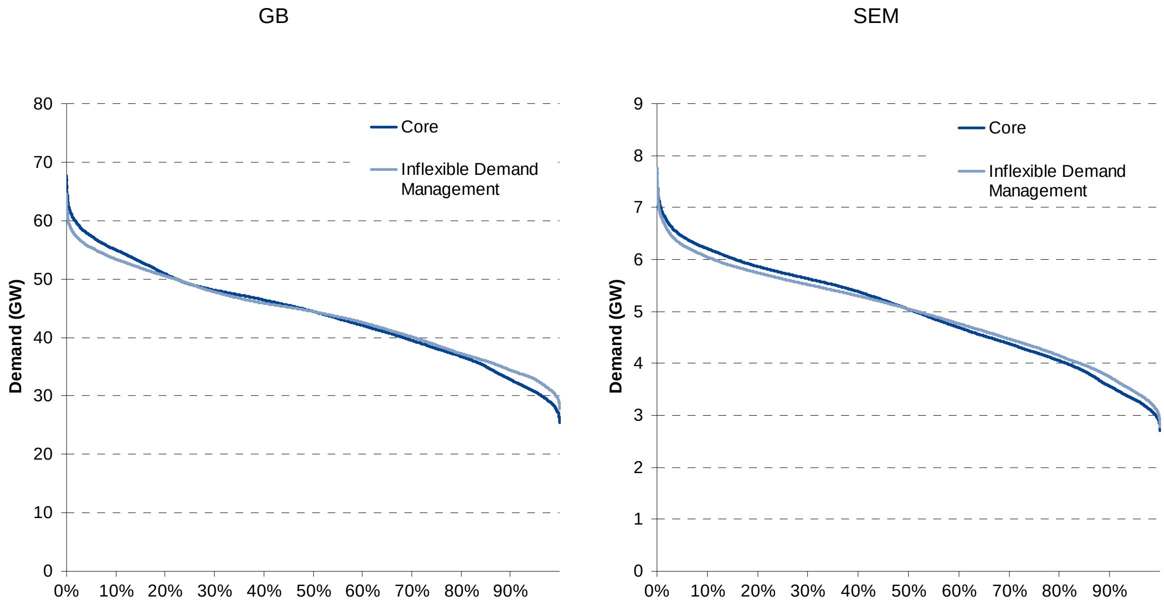


Table 20 gives the underlying assumptions for this scenario. For GB, we assume that an additional 600,000 domestic customers move onto a demand management tariff, whilst 3.2TWh of industrial and commercial customers move. Of particular importance is the deployment of electric vehicles, with almost 2 million assumed to be on the roads by 2020 and 5 million by 2030 in the SEM market.

Table 20 – Assumptions for Inflexible Demand Management scenario

	GB		SEM	
	2020	**2030**	**2020**	**2030**
additional TWh/year				
Domestic E7 change	4.2	5.25	2.0	2.7
Nondomestic E7 change	3.2	2.85	0.8	1.2
Electric Cars	4.1	10.4	0.5	1.0
additional # of customers ('000)				
Domestic E7 change	641	801	307	407
Nondomestic E7 change	105	93	27	38
Electric Cars	1,974	5,007	250	501

5.9.2 Price Responsive Demand Management (Smart meters) assumptions

Movable demand can be modelled as a form of energy storage: heat storage (in the case of demand from space or water heating) or battery storage (in the case of demand from electric cars) which generates energy during those periods which the demand is moved from and consumes energy during the periods which the demand is moved to.

Using the same assumptions for customers as the Inflexible Demand Management scenario, we calculate the total amount of movable demand each day based on projections of space heating demand growth in the domestic, services and industry sectors and the assumption that dynamically managed electric vehicle charging and space and water heaters must be on for a minimum of five hours each day in order to store sufficient energy to meet twelve hours of heat / electric car demand. For 2020, this leads to 22GWh of daily movable demand, with a charging capacity of about 4GW and a generating capacity of 2GW (comparing Table 21 to Table 22). By 2030, this has increased to almost 50TWh per day, with 10GW of charging capacity and 4GW of generating capacity.

Table 21 – 2020 Price Responsive Demand Management assumptions

			Daily movable demand GWh	Charging capacity GW	Generating capacity GW
Heat load	Domestic	Water	3.0	0.6	0.3
		Space	3.8	0.8	0.3
	Services	Water	2.3	0.5	0.2
		Space	8.5	1.7	0.7
	Industry	Water	1.5	0.3	0.1
		Space	1.7	0.3	0.1
Transport	Electric vehicles		1.4	0.3	0.1
		Total	**22.2**	**4.4**	**1.9**

Source:

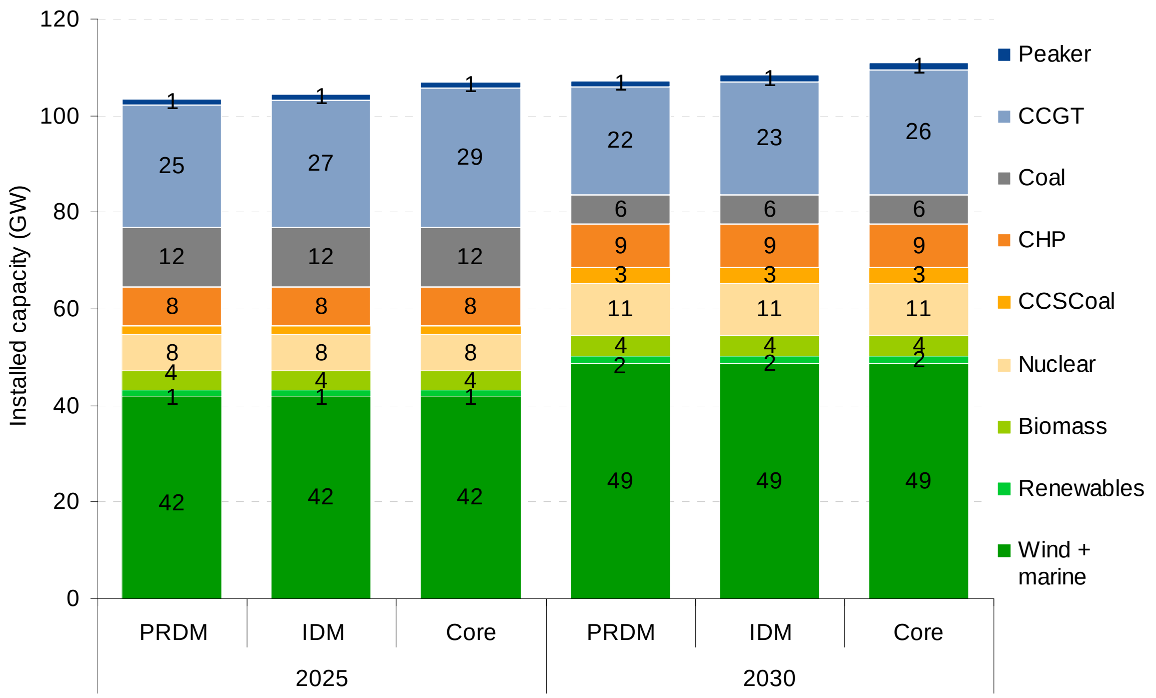
Table 22 – 2030 Price Responsive Demand Management assumptions

			Daily movable demand GWh	Charging capacity GW	Generating capacity GW
Heat load	Domestic	Water	10.7	2.1	0.9
		Space	6.8	1.4	0.6
	Services	Water	4.6	0.9	0.4
		Space	16.9	3.4	1.4
	Industry	Water	3.8	0.8	0.3
		Space	1.7	0.3	0.1
Transport	Electric vehicles		4.9	1.0	0.4
		Total	**49.4**	**9.9**	**4.1**

5.9.3 *What is the scope for demand side response to mitigate some of the impacts of high levels of wind generation?*

Both demand side management scenarios have the effect of flattening the demand curve, which alleviates the need for new build CCGT in GB to cover tight periods, as shown Figure 85. In 2030, 3GW less CCGT is required to be built to maintain the same level of system security in the Inflexible Demand Management scenario, whilst in the Price Responsive Demand management, 4GW less capacity is required due to the improved 'capping' of peak hours.

Figure 85 – Installed capacity in GB in 2025 and 2030 in the PRDM, IDM and Core scenario



The strength of price responsive demand management over inflexible demand management is that in a system with large amounts of wind capacity periods of low price may not exist at the same time every day: the effects of the variability of wind have a far greater effect on system tightness than fluctuation of demand. To demonstrate this, we present an illustrative sample of four days from the Monte Carlo 2000 run of February 2030 and contrast how the system manages load in

- the Core scenario, which has 1.8GW of pumped storage;
- the Inflexible Demand Management scenario, which has a flattened demand curve (and the above 1.8GW of pumped storage), and
- the Price Responsive Demand Management scenario, which has an additional 10GW of dynamically managed 'virtual storage' in the form of space and water heaters.

Figure 86 – GB generation patterns in February 2030 in the Core scenario

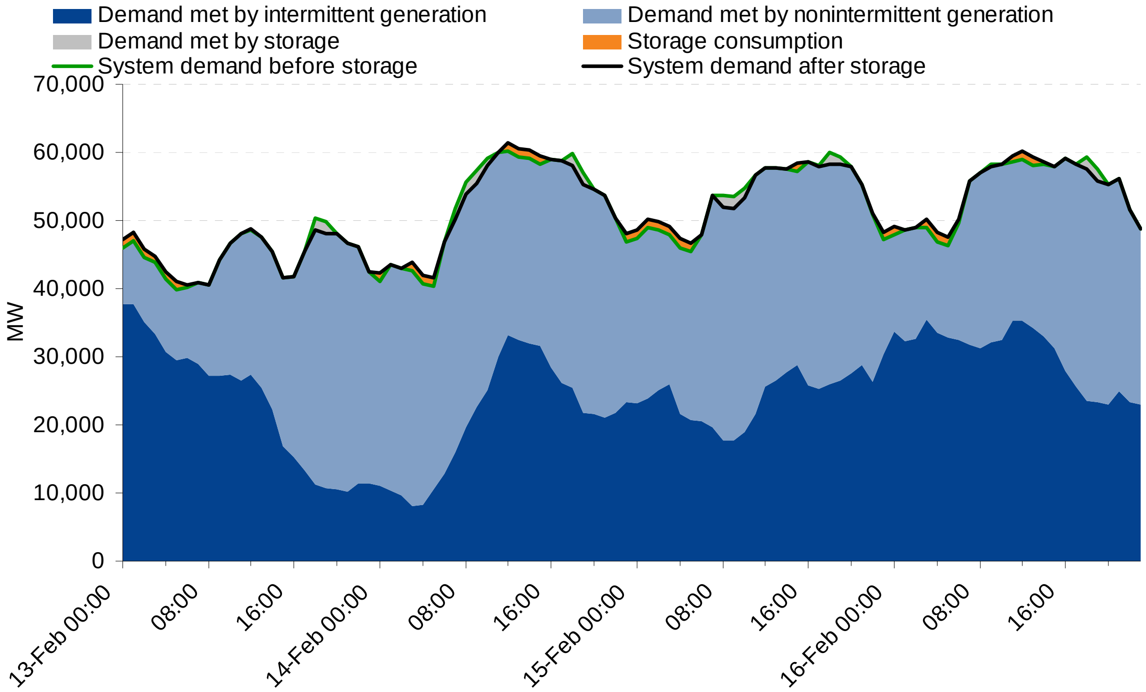


Figure 87 – GB generation patterns in February 2030 in the Inflexible Demand Management scenario

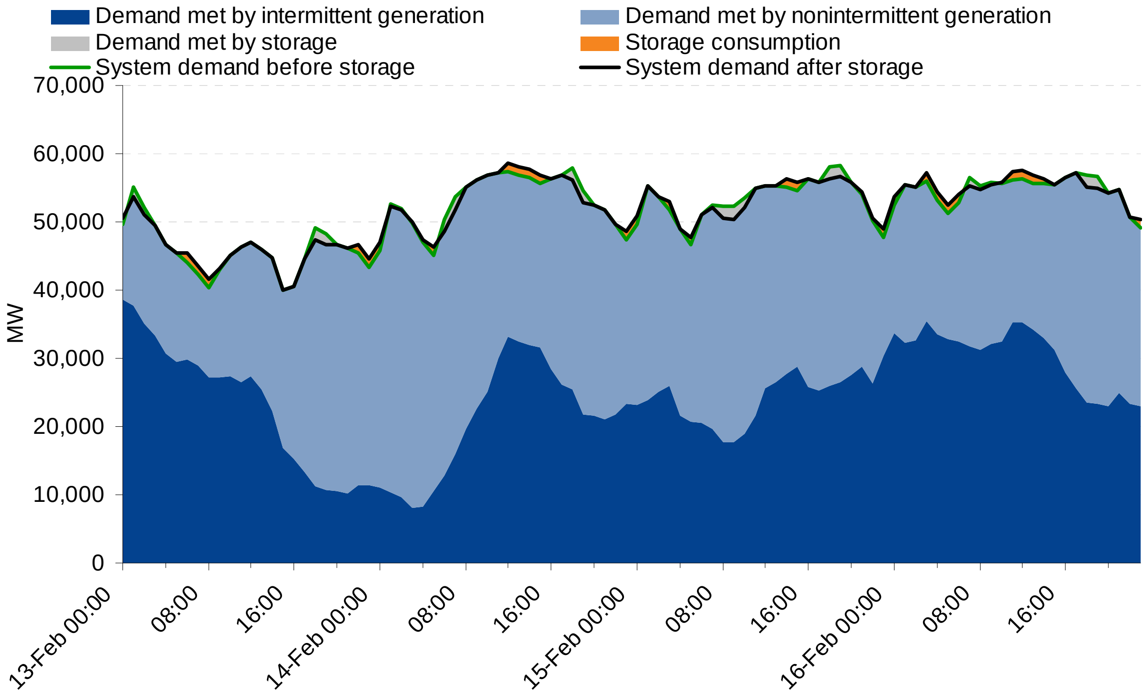
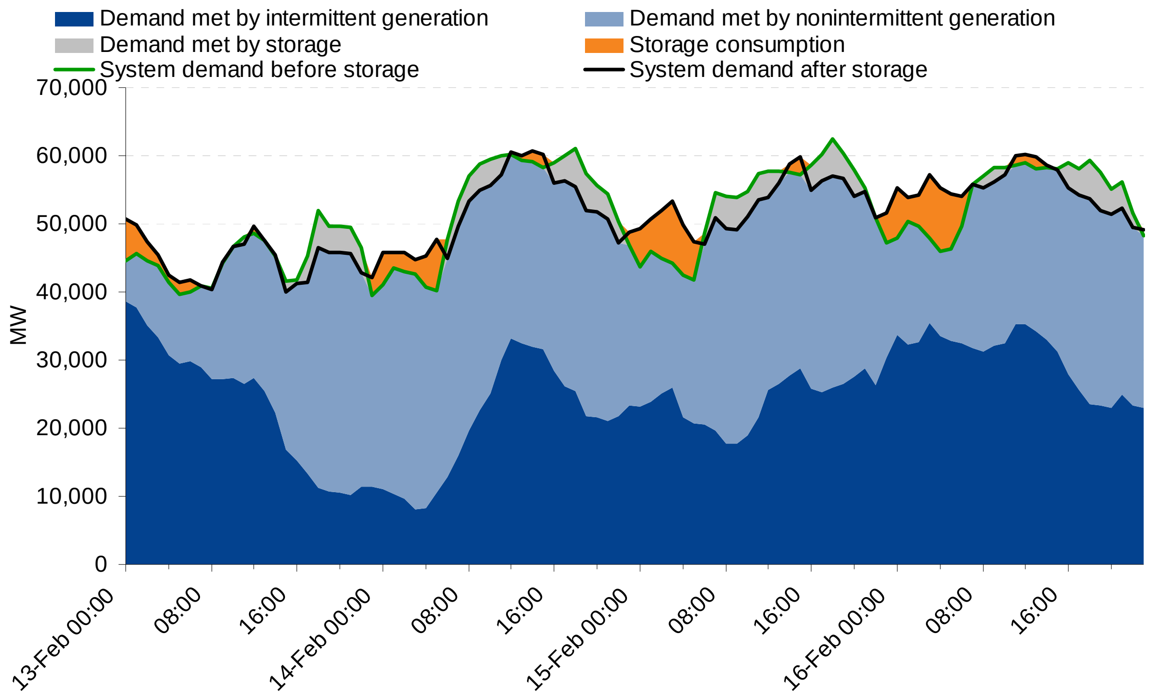


Figure 87 demonstrates that the inflexible demand management serves to flatten the demand curve, but that its inflexibility can end up making the problem worse, as is the case during 14 February 00:00-08:00, where the effect of the Economy 7 demand curve is to create extra load at a time when intermittent generation is already low. At 4am, demand in the Core scenario is about 40GW with only 8GW of wind generation. However in the Inflexible Demand Management scenario, demand has been driven up to over 50GW due to overnight demand from electric heating and charging.

Figure 88 – GB generation patterns in February 2030 in the Price Responsive Demand Management scenario

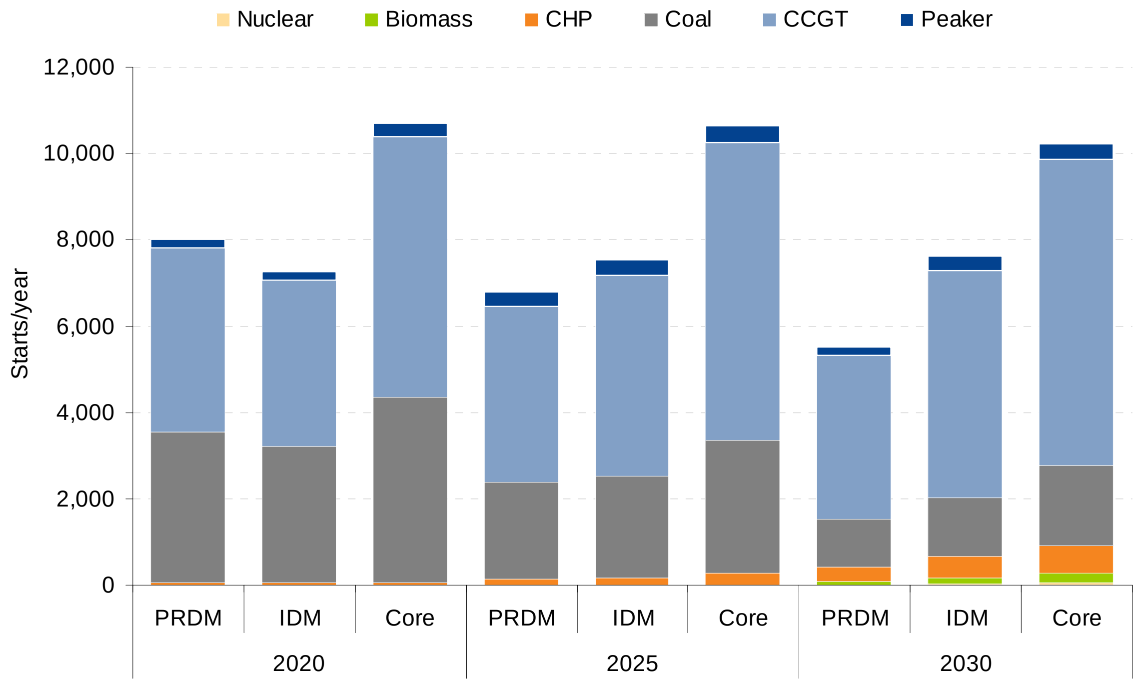


However, Figure 88 demonstrates the improvement to this situation with price responsive demand management, rather than inflexible demand. On 14 February in the early morning, demand rises to 45GW, leading to a much less stressed system overnight. Instead, the requirement for heating load is spread out over a longer time period, and some of it occurs during peak hours of the day, as generation from the wind rises from an overnight low of 8GW to a high 10 hours later of 32GW. In addition to easing the strain on the system by generating during times of low intermittent generation, the storage also acts to adjust the shape of the demand curve so that the demand for non-intermittent generation – the light blue and orange area in the graph – is flattened over the course of a day. This means that fewer starts are needed, reducing the need for thermal generators to waste energy running at minimum stable generation or activating a plant.

As such, we would expect only to see the number of starts in the Price Responsive Demand Management Scenario fall significantly towards the later end of the scenario. Until then, the Inflexible Demand Management Scenario is able to cope equally well with the challenges of intermittent capacity, as Figure 89 shows. By 2030, the number of starts per year is reduced from 10,000 across both GB and the SEM combined, to 7500 in the

Inflexible Demand Management scenario. With Price Responsive Demand management, that is reduced even further to 5,000 – a fall of 50%.

Figure 89 – Number of starts per year (in GB and SEM combined) of different technology types in the Core, IDM and PRDM scenarios



Source: Pöyry analysis

5.10 Summary of findings from further cases

Table 23 – Summary of conclusions from further cases

Capacity payment scenario	
What is the effect on prices? Are prices less peaky?	In 2016 and 2030, prices in the Capacity Payment scenario are lower, whilst in other years they are higher. The profile of monthly prices is flatter as generators do not need to recover costs in a small number of years. Hourly prices are much less volatile, with a similar number of low priced periods but much fewer high priced periods. SEM prices become much less volatile as well.
How is new build affected?	The capacity payment allows older CCGTs to stay on the system, and also incentivises new peaking plant in GB. Adjustments in the SEM are minor. Lower returns on CCGTs mean no new plant are built.
What is the impact on total system investment costs?	It is notable that the market arrangements have very little impact on total investment costs – since the vast majority of this is in wind. Irish consumers would benefit from lower market prices in the SEM if GB adopted a capacity payment – however generators would lose revenue as they would no longer benefit from the high prices that occur in the GB market in 2016 and 2030.
How are plant returns affected?	In GB, returns for OCGTs become much higher and compatible with new entry, whilst CCGT returns are driven downwards as prices are lower on average. In the Irish market, returns for CCGTs reduce for the same reason and as a result no further CCGTs are built.
Lower RES scenario	
What is the effect on prices? Are prices less peaky?	Prices in the Lower RES scenario are somewhat higher than the Core Scenario – due to less downwards pressure from wind. Lower RES prices are less peaky and have no zero or negative priced periods.
How do emissions change?	Emissions drop in GB, but only to 165gCO_2/kg in 2030, whilst in the SEM, emissions remain above 200gCO_2/kg.
What is the effect on generation?	In the Lower RES scenario, renewable share of generation reaches 33% by 2030 rather than 42%. In the SEM, renewable generation reaches 40% in 2020 and 50% in 2030.
What is the impact on wind cannibalisation?	In GB, overall wind revenues are higher as there is less wind depressing prices. The variations between sites are also suppressed.
Carbon drop scenario	
What are the implications on price?	With a carbon price that is £15/tCO_2 lower, wholesale prices drop substantially – by an average of £7/MWh. Overall price patterns are unaffected.
How are load factors affected?	The lower carbon price significantly increases load factors of coal plant and depresses F-class CCGTs. Neither nuclear nor peaking plant load factors are affected. The same pattern occurs in Ireland – higher load factors for coal with lower load factors for CCGTs.
How are plant returns affected?	As expected, IRRs of coal plant rise due to lower carbon costs, and those of CCGTs drop slightly in GB as coal generates more. In SEM, the CPM keeps peaking plant profitable.
How are emissions affected?	Overall, emissions are 10-20% higher with a carbon price £15/tCO_2 lower. This is due to higher coal generation which significantly increases emissions.

IED scenario	
Which plant close and what is required to replace them?	The IED has a potentially significant effect on GB plant. In particular, over 5GW of coal and 8GW of CCGT might have to close in 2020 in addition to the LCPD closures. However, this scenario is difficult to balance, as OCGTs have to be built to ensure returns to older CCGTs. If only new CCGTs are built, then other CCGTs would be displaced, leading to a 'race to the bottom'. There are negligible changes in SEM due to the IED. There is no new CCGT build as returns are too low.
What is the effect on prices?	Prices in GB are less spiky in 2016, but much more so in 2020 due to the retiral of plant. Prices in SEM are driven up in 2020 as well, though to a lesser extent.
What is the effect on emissions?	The closure of GB plant reduces emissions by almost 20MtCO_2 per year in 2020. However, much of this plant would have closed in 2025, so reductions after 2025 are much smaller, and negligible in 2030. Emissions in the SEM go up as a result of the plant closures in GB, as Irish plant generate more and the SEM exports more energy to GB.
Offshore deployment sensitivity	
How do prices and volatility change?	By 2030, despite the same volume of generation, prices are slightly higher as wind farms are more correlated with each other and hence system margins are tighter more often.
How does volatility change?	Price volatility increases marginally with higher offshore deployment, but it is not a significant change.
Severn barrage sensitivity	
How does plant operation change?	The Severn barrage has a noticeable effect on thermal plant operation, as it depresses thermal generation (CCGT) twice a day.
Does it affect prices?	Annual and monthly prices are slightly affected, with GB prices dropping by 2% in 2030 and SEM prices by 2.8%.
	The Severn barrage significantly increases price volatility in GB, and this sensitivity has the highest volatility of all our scenarios. Price volatility is almost 50% greater.
How do wind capture prices change?	Capture prices in the Severn barrage scenario are slightly lower than in the Core scenario, as the Severn barrage depresses prices when operating.
What is the impact on emissions?	The Severn barrage scenario results in the lowest emissions of all our scenarios, dropping to under 50MtCO_2 in 2030.
How much is wind output reduced?	A large Severn barrage increases wind loss significantly, from 55 to 2010 periods in 2025 in GB and 300 to 690 periods in 2030. It also has an impact on the SEM, increasing wind loss instances to over 1000 periods in 2030.

Interconnection sensitivity	
What is the effect on prices in GB and SEM?	The impact of changing interconnection is negligible on GB. In SEM, monthly and annual prices fall by between 2-5% as a result of 'stranded wind' – excess wind generation no longer able to be exported to GB.
What is the effect on interconnector flows?	The Interconnector scenario has lower overall flows, but the patterns remain very similar, with a move towards more exports from the SEM in winter by 2030. Interconnectors are constrained much of the time.
How do returns change for plant in SEM?	Reduced interconnection translates into lower returns for SEM plant across all class of plant, as the market is less interconnected to high GB prices in 2015-20 and excess wind cannot be exported to GB from 2020 onwards.
How much does wind output decrease?	Wind output decreases in both countries, but especially in Ireland, with an increase in periods of wind loss from 60 to 220 in 2020 and 700 to 1200 in 2030.

Inflexible demand management scenario	
Price responsive demand management scenario	
How does increased demand management affect demand?	With inflexible demand management, the demand curve is flattened, with more demand during off peak hours. The effect is greater with price responsive demand management, as demand is moved to where it has the greatest reduction on price.
What is the effect on number of plant starts	Demand management may make a considerable difference to the number of plant starts. By 2030, the number of starts per year is reduced from 10,000 across both GB and the SEM combined, to 7500 in the Inflexible Demand Management scenario. With Price Responsive Demand management, that is reduced even further to 5,000 – a fall of 50%.
What is the effect on investment in generation?	Investment in new thermal plant is reduced by 3GW for the Inflexible Demand Management scenario, and by 4GW in the Price Responsive Demand management scenario

6. TOPIC INVESTIGATION

The main aim of the study was to answer a series of questions posed about the electricity markets of GB and Ireland and how they are impacted by intermittency. These questions reflect the main areas of interest and concerns of the participants of the study.

The answers to these questions draw upon results from a range of the scenarios outlined in Section 0, focusing in particular upon the Core scenario.

6.1 Market prices

The Core scenario in section 4.1.4 gives a description of how market prices evolve and how the relationship between investment and prices changes over time. This section shows how market prices may evolve as a result of wind in the various scenarios and how volatility, zero priced periods and price shapes may change in the future.

6.1.1 How will market prices change?

Will average annual prices drop significantly?

Wind has an effect on wholesale prices in GB which is masked by other changes in the market – in particular the value of capacity. In the SMP, shown in Figure 90 on the left, market prices drop from £60/MWh in the Core scenario in 2015/16 to £58/MWh in 2020 and £52/MWh in 2030. Since commodity prices are the same in all years after 2015, this drop in SMPs is caused by the underlying changes in generation – and above all by the large volumes of wind generation on the system. This effect is very similar across the scenarios (all of which have the same underlying commodity prices), although is less pronounced in the Lower RES scenario due to the lower volumes of wind generation installed. For wholesale prices, however, the changes due to the value of capacity as the system becomes tighter and requires new entry are much more significant than the effect of wind pushing down prices – this leads to annual prices that do not show obvious changes due to intermittency, as shown by the wholesale prices in Figure 90 on the right.

Figure 90 – Annual SMP and wholesale prices in GB

In the SEM, the effects are much greater due to the smaller size of the market and the greater penetration of wind, as shown in Figure 91. In the Core scenario, SMPs drop from £61/MWh (€66/MWh) in 2015 to £49/MWh (€53/MWh) in 2030, with constant commodity prices – a fall of £12/MWh (€13/MWh). In the Lower stretch scenario, prices reduce in a similar fashion though to a lesser extent due to the lower installed wind capacity, falling from £60/MWh to £55/MWh by 2030. If Ireland had lower interconnection to GB than assumed in the Core scenario, there is greater downward pressure on prices due to more periods of zero prices as wind is de-loaded. This is shown in the Interconnection scenario in Figure 91. In this we reduce Irish export capacity by 820GW and reduce import capacity by 500MW. This reduction in expected build of interconnectors pushes prices downward by an additional £3/MWh compared to the Core scenario. In the SEM, the effect on wholesale prices is similar to that on SMPs since the Capacity Payment is broadly similar across all years.

Figure 91 – Annual SMP and wholesale prices in the SEM

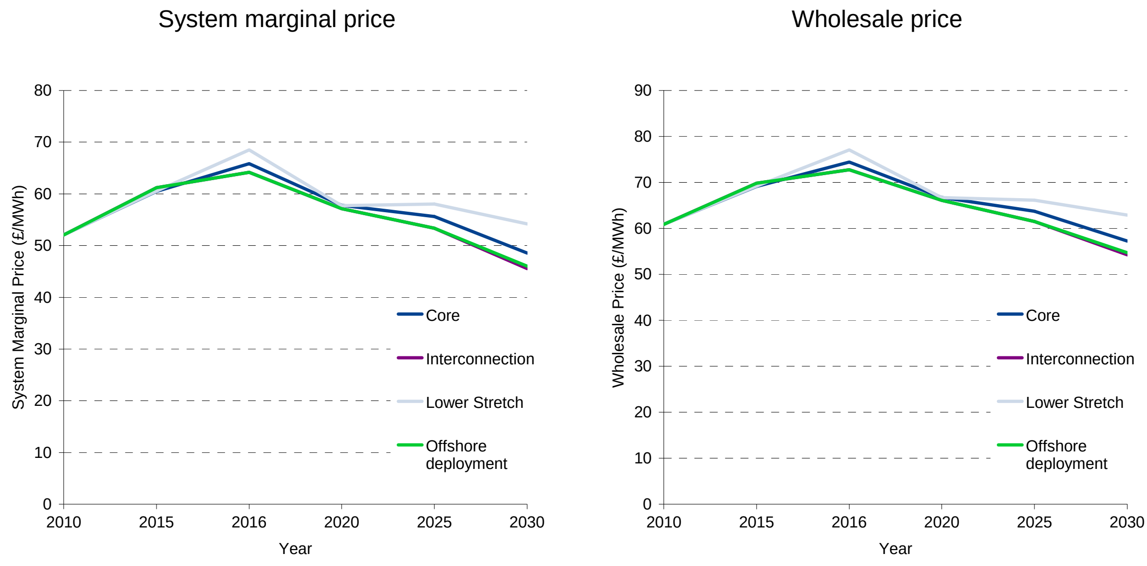
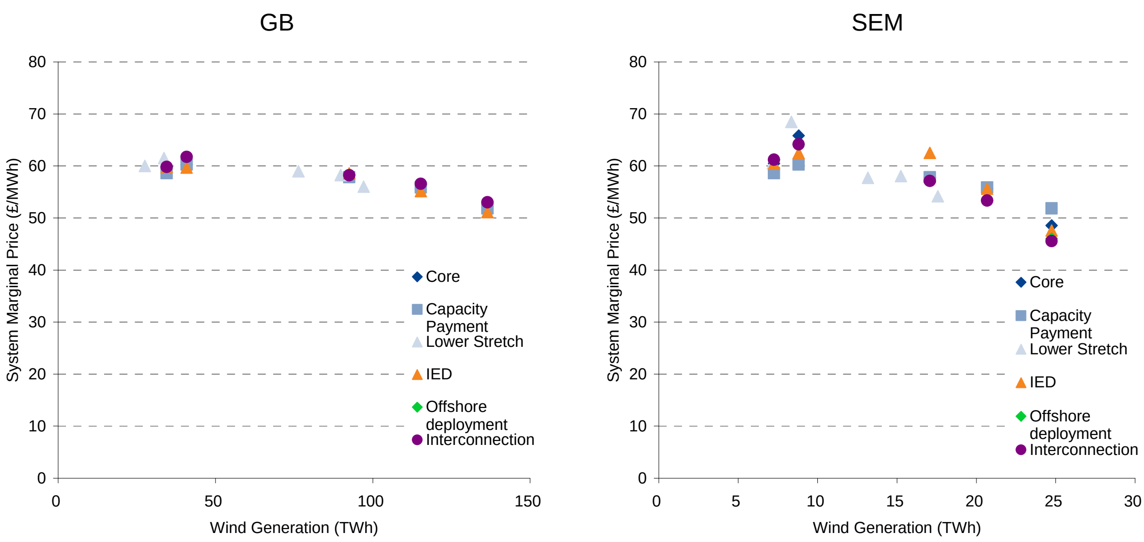


Figure 92 compares the annual wind generation to the SMP with each of the points representing a year and a scenario. Across all the scenarios and years, there is a definite relationship that as wind generation increases, overall SMPs decrease. In GB, an increase of 10TWh of wind generation (equivalent to around 3-4GW of wind capacity) drops prices by about £0.6/MWh, whilst in the SEM an increase of 10TWh reduces prices by £7/MWh (€7.6/MWh). An increase of 10TWh of wind generation is a much greater share in the SEM than in GB, which explains the stark difference in the results.

Figure 92 – Effect of wind capacity on annual SMP (all scenarios)



What will be the distribution of market prices within year?

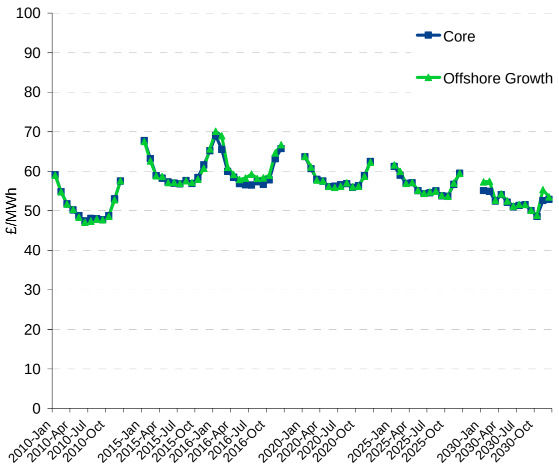
A future where there is a significant volume of wind baseload generation may have a changing profile of prices across the year. Historically, prices have been much higher in the winter than the summer, due to a combination of higher demand and higher gas prices. However, in the UK and ROI, there is significantly more wind in the winter months than the summer months – typically wind generation in the winter is approximately double that during the summer. This will have a countervailing effect on the monthly price profiles.

Figure 93 shows SMP (System Marginal Price) and wholesale price in GB in 2015, 2020 and 2030 in both the Core and Offshore Growth scenarios. The monthly SMP prices in 2015 show seasonality driven by gas prices and demand of about £10/MWh – between £57 and £67/MWh. By 2020 this profile has flattened, and by 2030 has a different shape, with lowest monthly prices occurring in October and the highest in January.

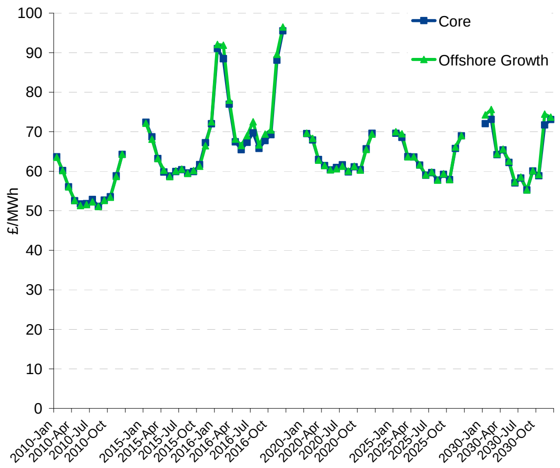
Wholesale prices, shown on the right in Figure 93, incorporate the effect of the value of capacity as well. The flattening of the SMP profile is not repeated in the wholesale price as the value of capacity grows in 2030 as a result of new generation requirements – the value of capacity is smeared more into winter prices than summer prices as that is when the periods of highest system tightness occur.

Figure 93 – Monthly SMP and wholesale prices in GB (Core and Offshore Growth)

Monthly SMP

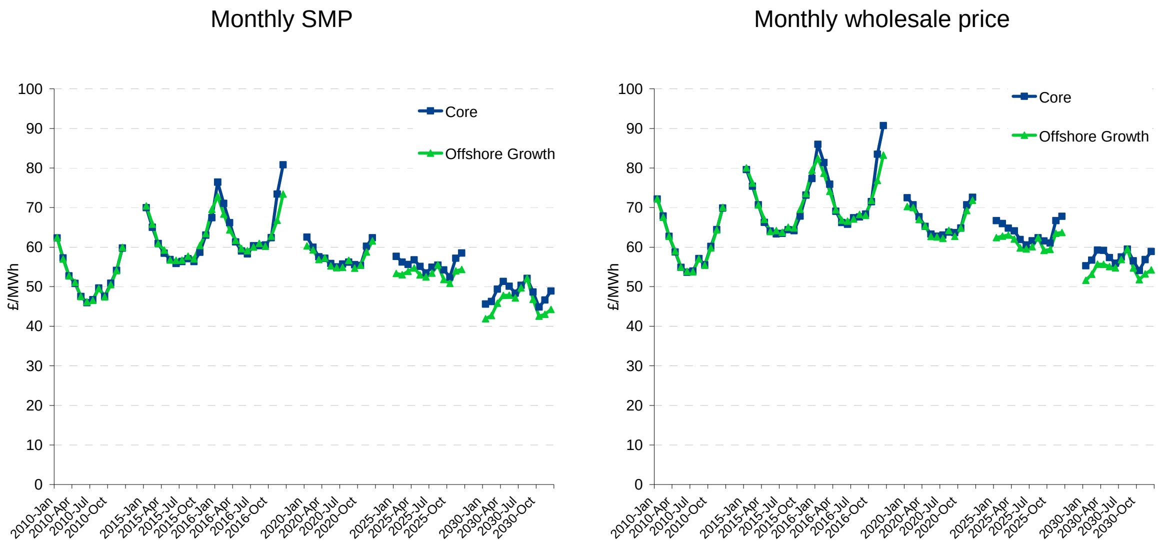


Monthly wholesale price



In the SEM, prices will become much flatter than currently. The monthly seasonality in SMP changes from predictable winter-summer swing in prices to an inverted profile where summer prices are on average higher than winter, as shown in Figure 94. This is because the wind generation in winter in Ireland gives a large number of low and zero-priced periods by 2030. The wholesale prices including the effect of the CPM show a very similar profile to that of the SMP due to the relatively flat profile of CPM payments.

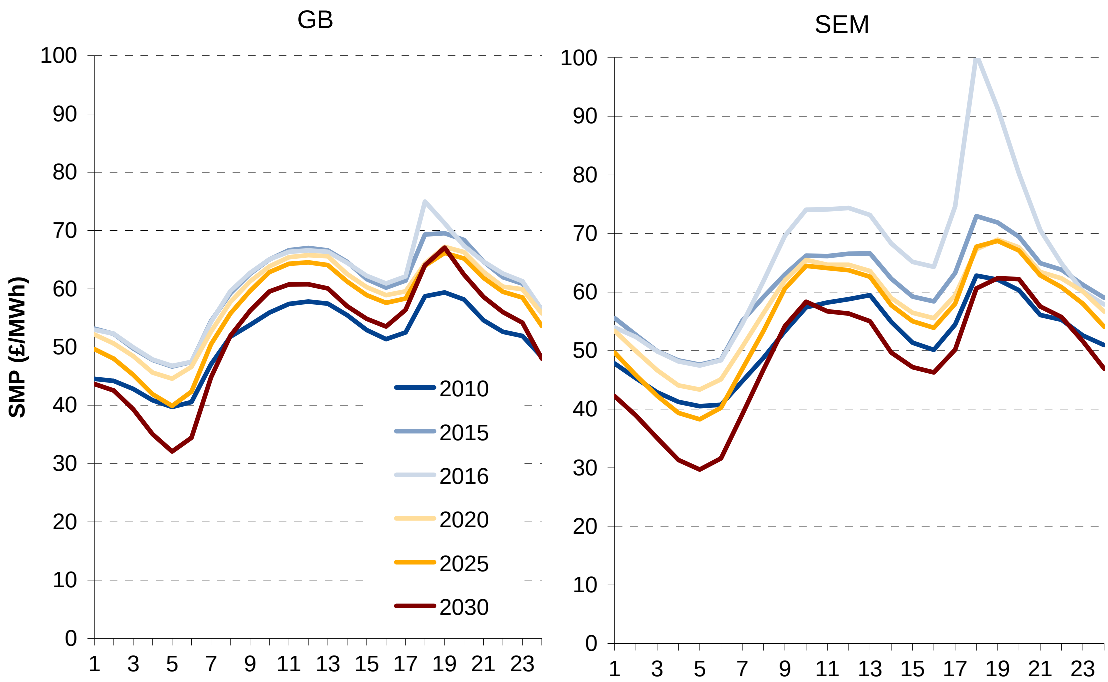
Figure 94 – Monthly SMP and wholesale price in SEM (Core and Offshore Growth)



How do within-day profiles change?

Within-day profiles do not fundamentally change shape, as the profile of demand within-day still remains a major driver of prices as it requires units to switch on and off. This is shown in Figure 95. SMPs in the SEM are dragged upwards in 2016 due to the effect of high value of capacity in the GB market. Overnight prices by 2030 are quite a bit lower in both markets due to the effect of wind and increased amounts of baseload generation. However, the spread or range of prices around this average increases significantly, with a large number of periods where prices are much below or much above this average.

Figure 95 – Hourly SMPs in GB and SEM



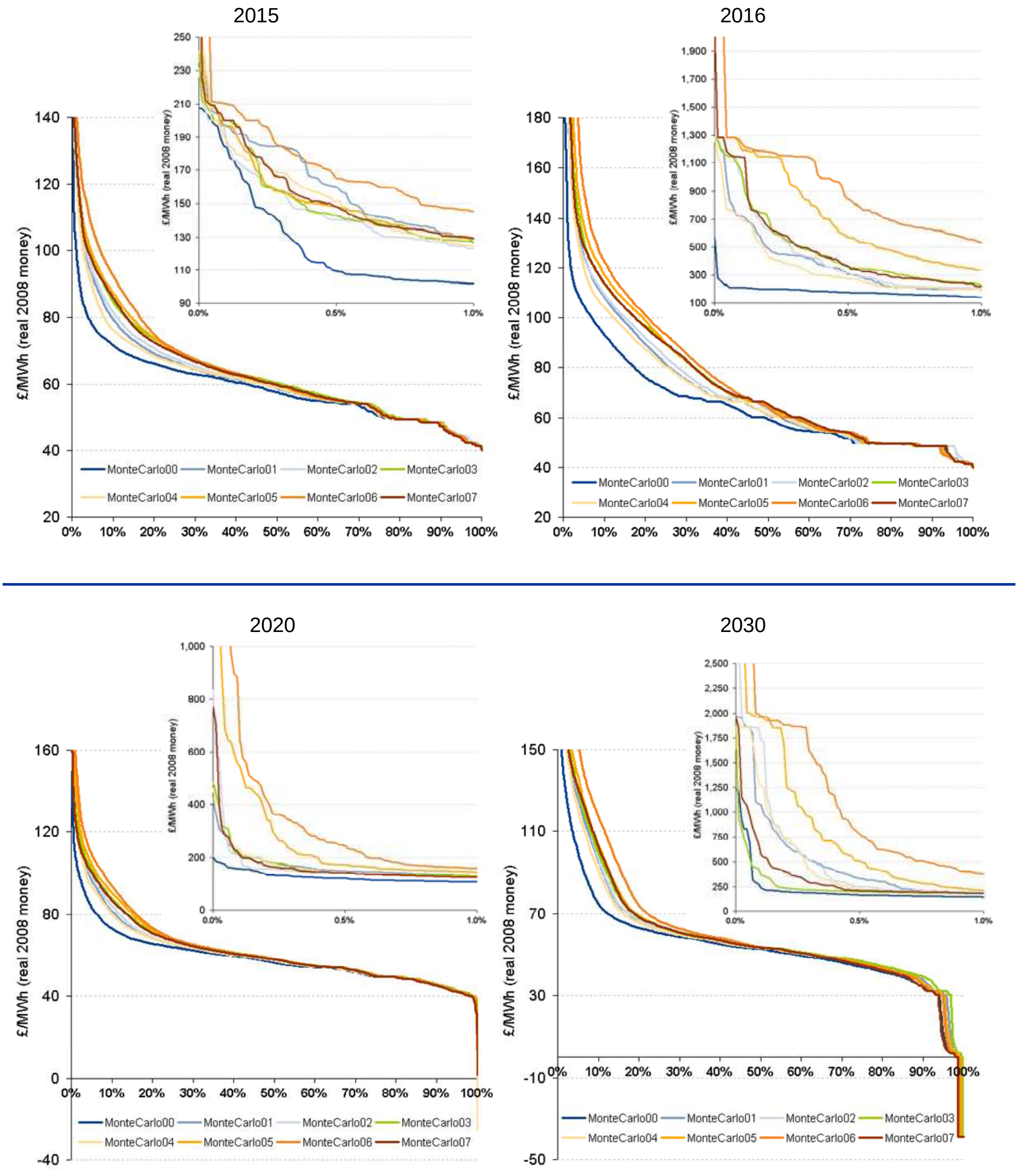
6.1.2 How does price volatility change?

What will hourly prices look like?

In GB in the Core scenario, prices are likely to become much more 'peaky' – increased periods with very high or very low prices. This is because the system will alternate between having too much capacity in periods with high wind speeds and high wind generation, and much tighter capacity when there are low wind speeds. By 2030, with significant volumes of wind on the system, the distribution of prices will change. There will be periods of negative prices due to the wind generation bidding at its opportunity cost of -1 ROC, periods with low or zero prices and some periods with very high prices above £1000/MWh.

During tighter periods such as 2016, wholesale prices may jump above £1000/MWh for a period of 3 or 4 hours – typically coinciding with demand peaks in the evening.

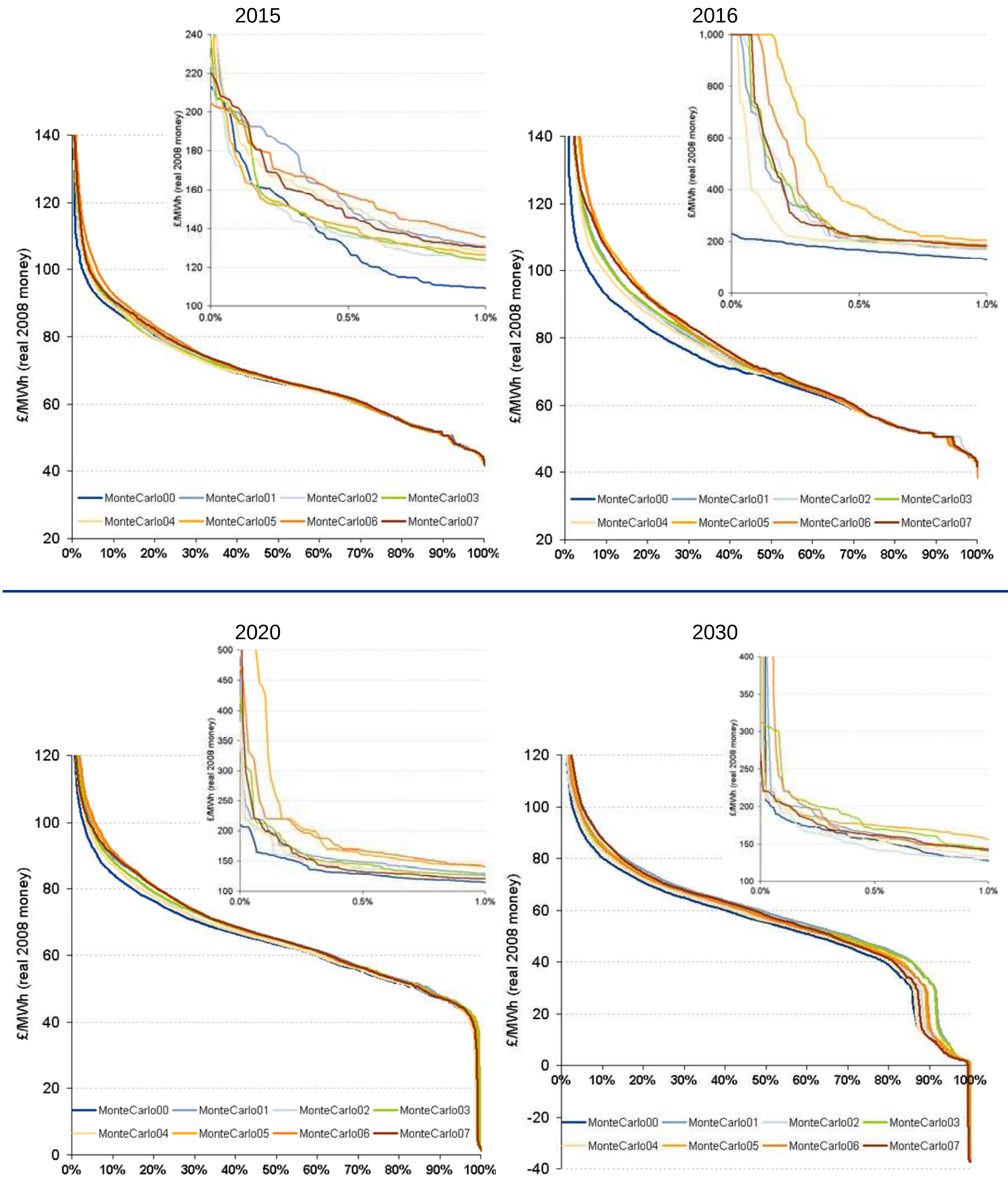
Figure 96 – PDCs for GB market in Core scenario



Note: PDCs are Price Duration Curves – all prices in a year sorted from highest to lowest. Prices spike to £7000/MWh in 2016 and £7700/MWh in 2030.

In the SEM, although prices will become more extreme than currently, they will not be as volatile as GB prices (setting aside the price floor and cap which are presently in place). There will be more low and zero priced periods than in GB due to the higher volumes of wind generation as a share of the market, though (due to our assumed bidding of wind in ROI at zero) very few negative priced periods. The extremes of high prices that GB may experience will be tempered in the SEM due to the CPM, although GB will maintain a strong influence on SEM prices.

Figure 97 – PDCs for the SEM in Core scenario



Note: PDCs are Price Duration Curves – all prices in a year sorted from highest to lowest.

How often will prices drop to (near-)zero?

Prices in a market dominated by baseload and intermittent generation will frequently drop to low levels as thermal plant is pushed off the system and plant with very low or negative marginal costs sets prices. Table 24 shows the number of hours in which prices drop to low levels in selected scenarios, split by price bands.

In GB, the Core scenario has no low priced periods in 2010, but by 2020 there are a few hours in which prices are zero or negative. By 2030, the combination of nuclear, CCS coal, biomass and wind creates over 70 hours a year on average where prices are less than -£30/MWh – typically -£39/MWh which is the opportunity cost assumed for UK onshore wind. Equally, the number of periods when prices are between zero and £10/MWh increases substantially to 280 – about 3% of the year.

In the SEM, there are far fewer negative priced periods as wind is modelled to bid at marginal cost (assumed in ROI to be zero); thus in 2030 there are only 29 hours in which prices drop below -£30/MWh (-€33/MWh). There are, however, many more low priced periods in the SEM due to the higher wind penetration and smaller market size – thus in 2030, there are over 700 hours when prices are between £0 and £10/MWh, and over 1000 when prices are below £20/MWh.

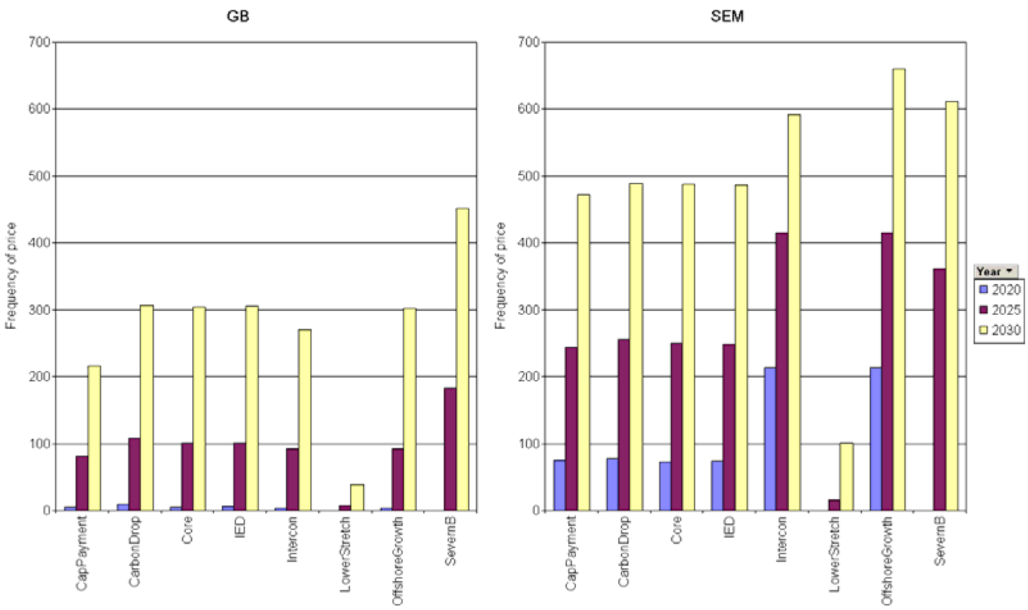
Table 24 – Periods of low prices by band across scenarios

GB		Count of hours when prices are: (£/MWh)					
		< -30	-30 to -20	-20 to -10	-10 to 0	0 to 10	10 to 20
Core	2010	0	0	0	0	0	0
	2020	0	0	0	0	6	1
	2030	73	3	0	0	280	48
Lower RES	2010	0	0	0	0	0	0
	2020	0	0	0	0	0	0
	2030	0	0	0	0	41	4
Severn Barrage	2010			NOT RUN			
	2020						
	2030	179	4	0	0	311	53

SEM		Count of hours when prices are: (£/MWh)					
		< -30	-30 to -20	-20 to -10	-10 to 0	0 to 10	10 to 20
Core	2010	0	0	0	0	0	0
	2020	0	0	0	0	83	3
	2030	29	3	0	0	699	249
Lower RES	2010	0	0	0	0	0	0
	2020	0	0	0	0	0	0
	2030	0	0	0	0	109	6
Interconnection	2010	0	0	0	0	0	0
	2020	0	0	0	0	279	26
	2030	5	1	0	0	1051	481

Examining low priced periods (<£5/MWh) across all the scenarios shows that the conclusions are similar for many of the scenarios due to the fact that the installed wind capacity is similar across these scenarios. Unsurprisingly there are far less low priced periods in the Lower RES scenario, owing to the lower volumes of wind that are built. Thus in the GB market where 29GW of wind are built by 2030, the number of low priced periods drops to only 6 in 2020 and 40 in 2030, whilst in the SEM it is 16 and 100 respectively.

Figure 98 – Periods of prices <£5/MWh



How much will price volatility increase?

Given the changing profile of prices and the increase in the number of periods when prices are extreme, it is unsurprising that price volatility increases. However, given a market with zero or negative prices, traditional measures of volatility break down.

Normally, volatility is defined as the standard deviation of the log of price returns.

Volatility = stdev[log($(P_h)/(P_{h-1})$)] for all prices P at hour h.

However, this metric breaks down with negative prices – there is no meaningful result for the log of a negative number.

Equally, defining volatility as the standard deviation of price returns cannot be used as if prices are zero it becomes insolvable – you cannot divide a number by zero.

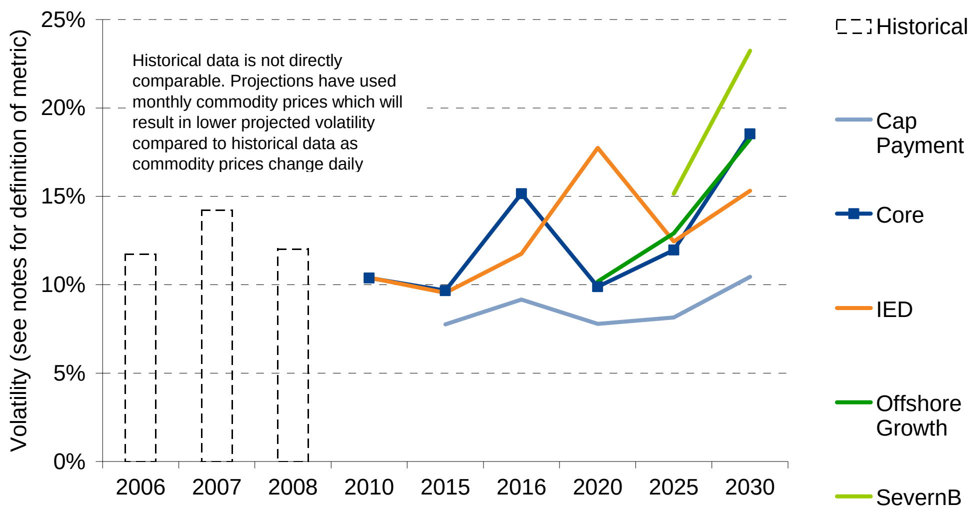
Volatility = stdev($[P_h/P_{h-1} -1]$) for all prices P at hour h.

Hence for price volatility we have used a revised metric – the average absolute change in prices as a fraction of annual average prices. This measures the absolute hourly change in prices, $|P_h/P_{h-1} - 1|$ averaged across the year, and then divided by annual average prices.

As shown in Figure 99, price volatility increases sharply in all scenarios from 2010 onwards. It should be noted that historical volatility is not directly comparable as the future prices are modelled with monthly or annual commodity prices, whilst historical prices incorporate daily commodity prices. The Core scenario experiences a sharp jump in price volatility in 2016 as the system becomes tighter. Volatility then drops, but rises even higher by 2030 as a result of price volatility due to wind generation and higher overall prices due to new entry.

Of all the cases, the Severn Barrage, where 10GW of tidal barrage are built, has the highest volatility due to the impact of the barrage on prices. The Offshore Growth scenario has very similar volatility to the Core scenario despite the greater geographical concentration of the wind in the North Sea. This is a surprising result as 20GW of wind near the Wash and on the Dogger Bank is highly correlated, and could be expected to drive significant prices spikes and dips. Although this may be the case, it is not significantly more correlated than wind generation across GB in the Core scenario, and hence does not drive up volatility significantly.

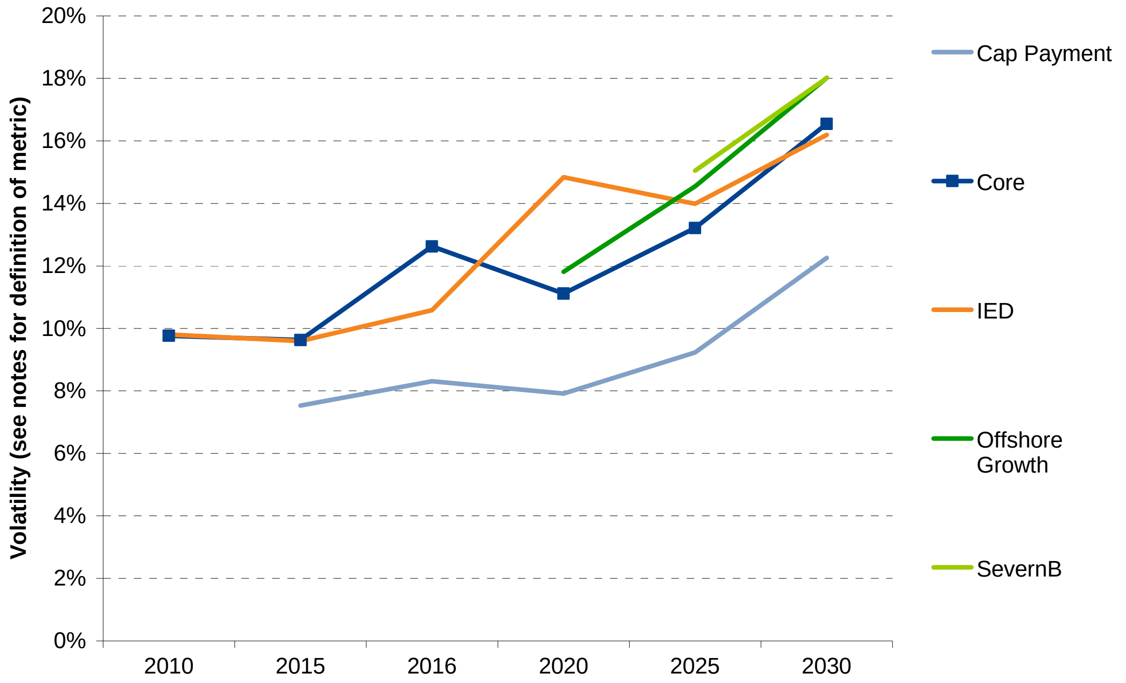
Figure 99 – Hourly price volatility in GB



Note: Volatility defined as average absolute change in prices as a fraction of annual average prices.

For the SEM, price volatility in 2010 is similar to that of the GB market. However, volatility does not increase to the same extent as the GB market despite even higher levels of wind penetration due to the dampening influence of the CPM. Some of the volatility in prices is ‘imported’ from GB, but this is limited to a certain extent by the capacity of the interconnectors.

Figure 100 – Hourly price volatility in the SEM



6.1.3 How do different wind years affect prices?

The interaction between wind, demand and availability has an influence of prices, particularly when the system is tight. Using historical data, certain years will have more periods where low wind and high demand coincide together.

Figure 101 shows how annual prices vary by Monte Carlo (historical) year for the GB market, with all Monte Carlo simulations run with exactly the same set of commodity price and capacity inputs – the only change is in wind, availability and demand. In 2010 there is a spread of about £5/MWh between the simulations, but by 2030 this has increased to almost £20/MWh. Thus as the volume of wind increases, the more sensitive outturn annual prices become to the interaction of wind, plant availability and demand. Thus the risk of operating in the market will increase – any one of the 8 Monte Carlo simulations could be the outturn price, and a series of low priced years could result from this interaction.

Figure 102 shows the average wholesale price and the spread for both GB and the SEM. The spread in the SEM is much smaller than in the GB market, with a range of £1.5/MWh (€1.64/MWh) in 2010 rising to £6.4/MWh by 2030. This highlights the different profiles of the market designs – the SEM market design is lower risk, with lower price volatility and a lower risk of extreme prices, whilst the GB market is higher risk with a higher likelihood of extreme prices.

Ultimately, the market risk would be borne by end-users, as utilities would demand higher prices to compensate them for the higher risk in the market.

Figure 101 – Wholesale prices for GB in different Monte Carlo simulations

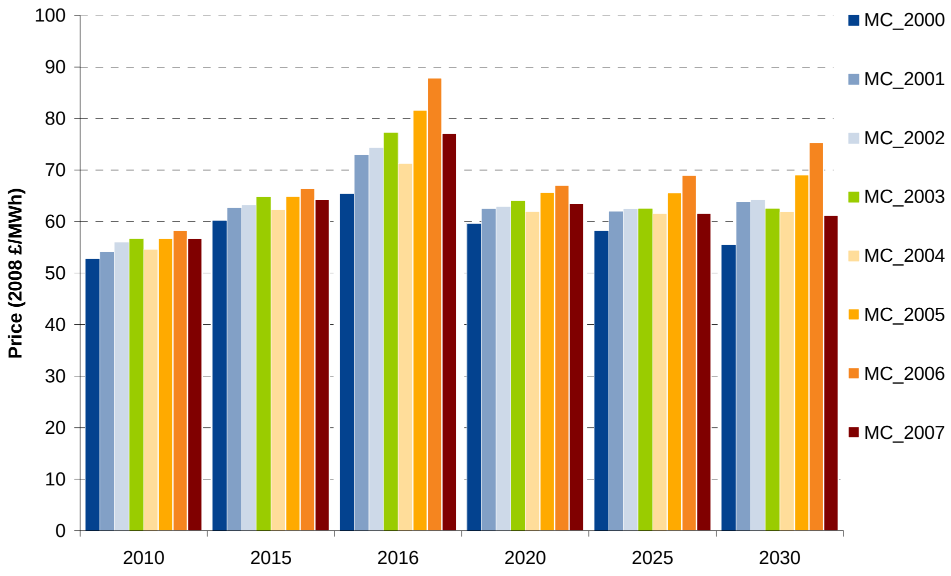
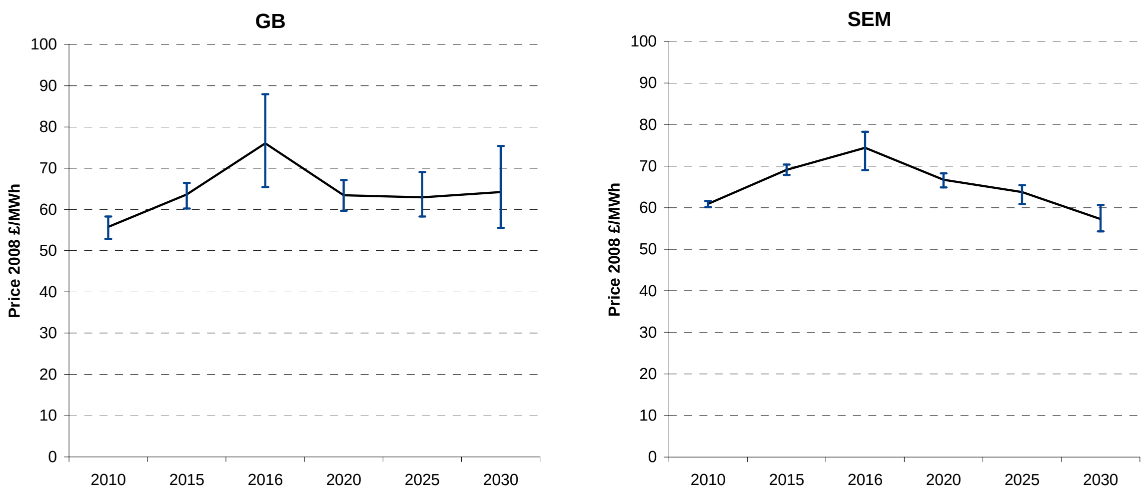


Figure 102 – Annual wholesale prices and spread across Monte Carlo iterations



6.2 Plant operation

6.2.1 How is thermal generation operation and revenue affected?

As discussed in section 4, load factors of conventional thermal plant are strongly impacted by high volumes of wind and baseload generation. Figure 103 and Figure 104 show load factors across a range of scenarios for GB. By 2015, the main plant to be affected are the older E-class CCGTs, and load factors of coal plant increase in 2016. In GB by 2020, load factors of older E-class CCGTs are below 10%, and newer F-class plant are under 60% whilst coal is at 50%. The main reason for this is the reducing 'space' for these plant to operate in – with rising volumes of baseload nuclear, CCS coal and biomass plant, and increasing volumes of intermittent generation, their running patterns by 2020 are increasingly the inverse of wind generation

By 2030, even CHP, biomass and to a lesser extent nuclear are displaced by wind generation at certain times of the year, pushing load factors downwards.

The load factors in the various scenarios show results as expected, with all the scenarios consistent in decreasing load factors for CCGTs, although the Lower RES scenario has less of a drop. Coal plant are also affected in a similar manner, although in the Carbon drop scenario, load factors remain higher due coal running ahead of gas much of the year.

Figure 103 – Load factors for CCGT plant in GB in different scenarios

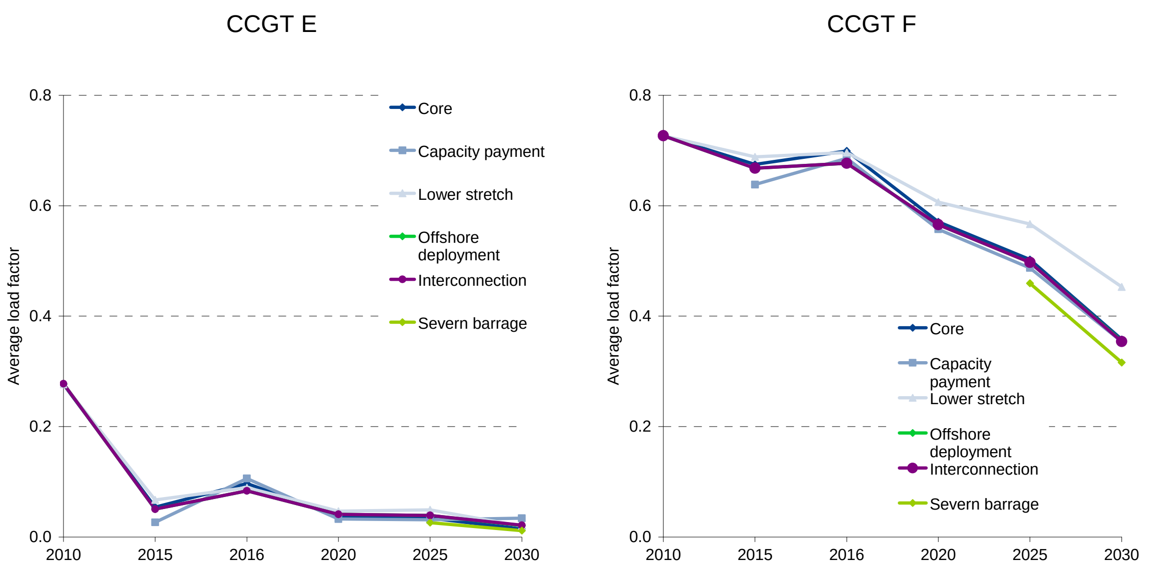
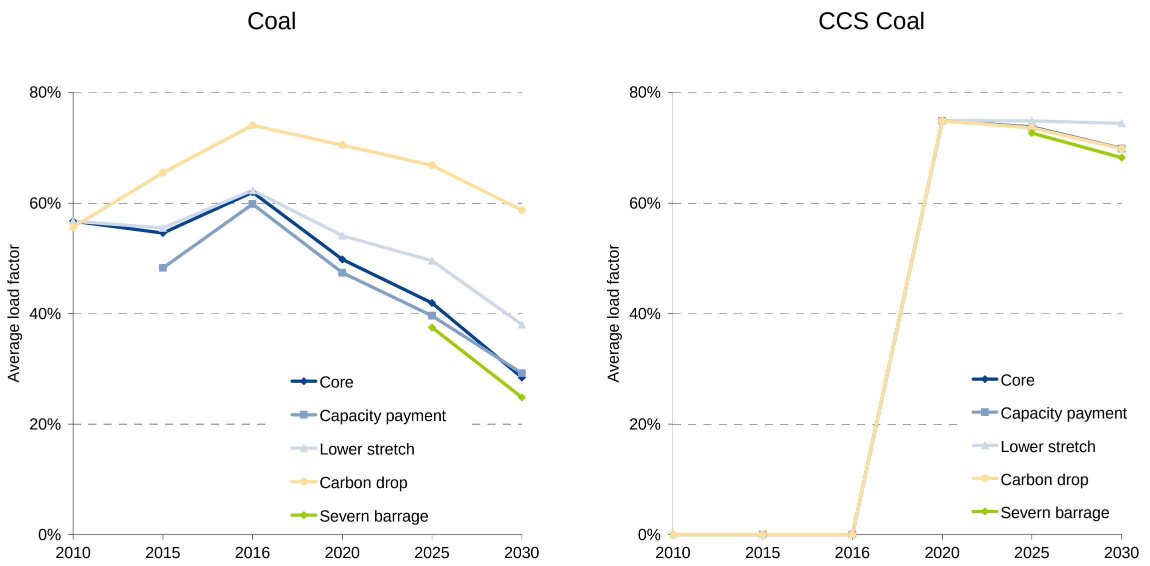
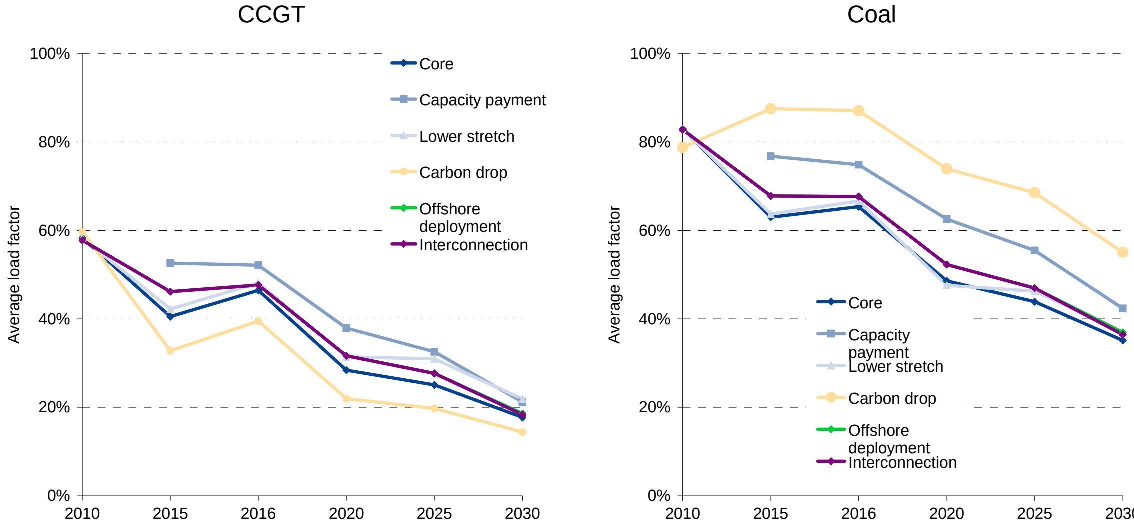


Figure 104 – Load factors for coal plant in GB in different scenarios



In the SEM there is a similar pattern, as shown in Figure 105, although more of a variance across the scenarios due to the smaller market being much more sensitive to changes in capacity assumptions.

Figure 105 – Load factors for plant in the SEM in different scenarios



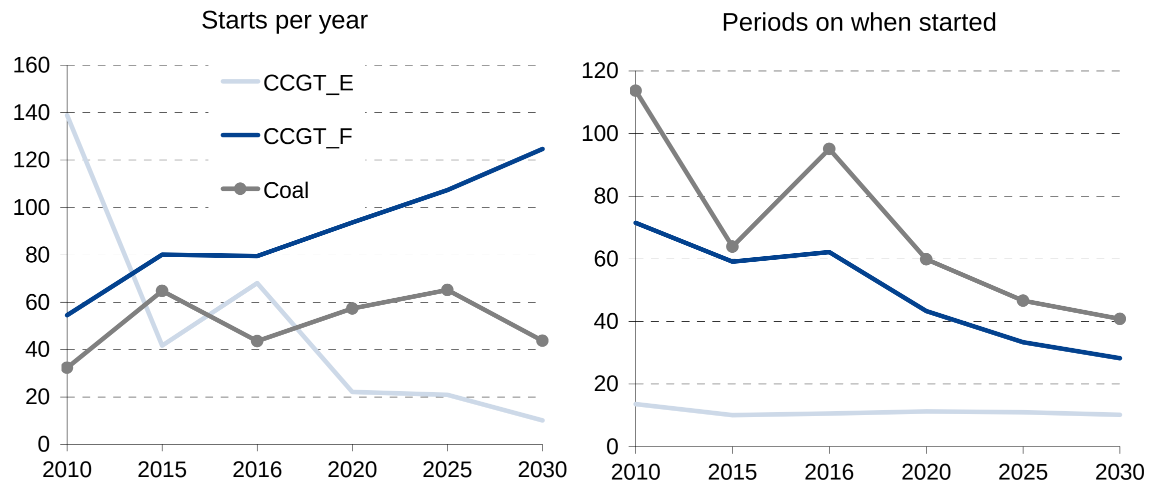
How much start-up and part-load does this imply?

With increasing volumes of wind, the existing thermal generation on the system has to fulfil a changing role, with a limited role for baseload generation and much more need for mid-merit and peaking generation modes of operation.

In GB, as shown in Figure 106, newer F-class CCGTs have an increasing number of starts and a reducing period when they are on. In 2010, they typically run with 50 starts and are on for around 70 hours (3 days) – this will be running 5 days a week for some units and less for others. By 2020, the number of starts has increased to 90 a year, with units on for only 60 hours. By 2030, they start 120 times a year and run for about 25 hours. However, older E-class CCGTs have fewer starts. In 2010 they typically run two-shift, running for around 14 hours when on and starting 140 times a year. The number of starts then falls as the units are called upon to operate less and less, so that by 2020 they are starting only 20 times a year, and operating 13 hours each time.

For coal plant, the number of starts stays roughly constant. This is due to two factors – firstly coal tends to run ahead of gas in the Core scenario due to the relativity of carbon, coal and gas prices. Secondly the plant left after 2016 are the highest efficiency plant – thus the number of starts drops in 2016 as the older coal plant that have not fitted FGD close, and only the newer plant with FGD remain. However, the length of the period on when started decreases sharply in line with the reducing load factors of the coal plant overall.

Figure 106 – Starts and periods on when started in GB – Core scenario

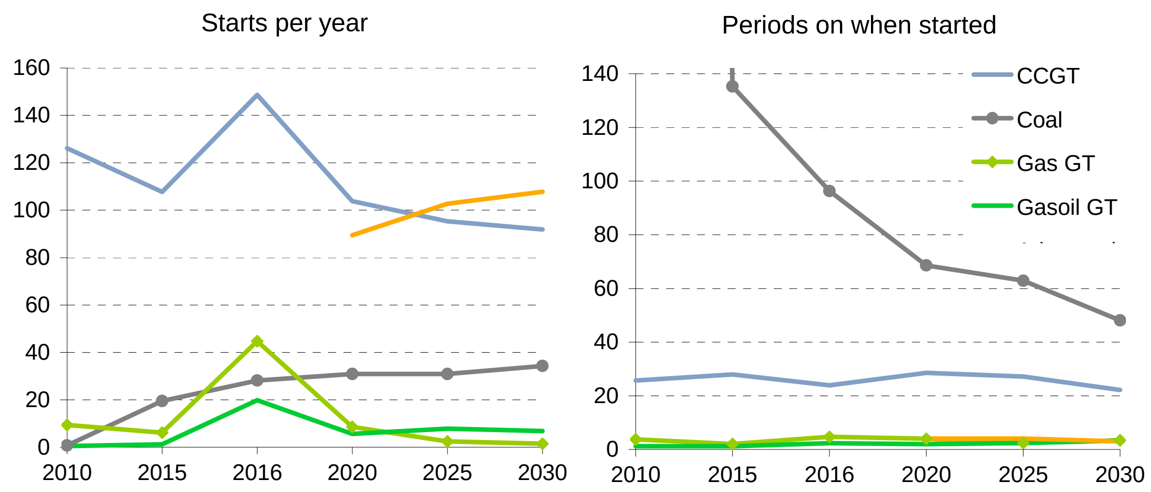


Starts exclude starts due to outages

In the SEM, as shown in Figure 107, the picture is more complex due to the smaller size of the market – the results are more sensitive to how a single plant is operating. CCGTs experience falling load factors, and start less often though remain on for a similar length of time. The jump in load starts in 2016 is due to the tightness in the GB market and the very high prices – Irish plant generate more in response to GB price signals and start more often. Coal plant that was baseloading in 2010 starts about 30 times a year by 2020.

However, the significant change in operating patterns for coal and CCGTs that was observed in the GB market is not seen in the SEM even though wind penetration is much greater – this is mainly due to the existence of larger numbers of peaking plant. The more less efficient peaking plant are starting 8-10 times a year and are on for 3 to 4 hours, with the advanced GTs starting 100 times a year with similar on times.

Figure 107 – Starts and periods on when started in SEM – Core scenario



Starts exclude starts due to outages

6.2.2 What impact will cycling have on plant emissions?

As shown in Table 25, emissions fall rapidly in both GB and SEM with increasing renewable and low emissions technologies, from 168MtCO_2 in GB in 2010 to 50MtCO_2 in 2030, and emissions in the SEM falling from 18.7MtCO_2 to 7.6MtCO_2 by 2030. Only a small proportion of this is due to starting and part-loading plant – typically around 2% – with the majority from running plant. However, the proportion of CO_2 emissions from starting and part-loading plant does increase – from about 1.4% in both markets in 2010 to almost 3% by 2030.

Overall, although the amount of CO_2 emitted from starting and part-loading plant does increase, it still remains a small share of the total, and unlikely to be of significance until the volume of zero carbon generation drops to very small levels.

Table 25 – Share of emissions from generation and start-up/no-load (SU/NL)

	GB			SEM		
MT CO2	CO2 from generation	CO2 from SU/NL	SU/NL as %	CO2 from generation	CO2 from SU/NL	SU/NL as %
2010	168.3	2.4	1.4%	18.7	0.3	1.3%
2015	145.6	2.4	1.6%	14.1	0.3	2.0%
2016	143.9	2.3	1.6%	15.6	0.3	2.2%
2020	117.7	2.2	1.9%	10.8	0.3	2.3%
2025	82.0	1.8	2.2%	9.6	0.2	2.4%
2030	49.5	1.3	2.6%	7.6	0.2	2.8%

Results from the Market Schedule model runs.

6.3 New thermal generation

6.3.1 How much new thermal generation might be required?

The amount of new thermal generation (unsubsidised) required in the Core scenario is relatively low, primarily due to an assumed low demand growth until 2030, and very significant growth in renewables, and biomass. In GB, a total of 5.8GW of already committed new CCGTs are built between 2010 and 2015. Given this build, low demand growth and the renewables, no new 'generic' (i.e. currently unplanned) CCGTs are required in 2016 to cover the retiral of 10GW of plant under the LCPD. This retiral leads to a tighter system, but one that still is within our two hour LOLE. Following the LCPD closures, 3.2GW of new nuclear comes online by 2020 and a further 6.4GW afterwards, and 3.2GW of CCS coal by 2030.

Of the older CCGTs, 2.4GW close in 2020 as they do not cover their fixed costs on an annual basis, and a further 5GW close by 2030 – due to the combination of fixed cost recovery and the age of the plant. In 2030, significant new entry of CCGTs is required with the retiral of many older and ageing plant.

If the IED is implemented in its strictest reading, with the closure of an additional 13GW of plant in 2020, there could be a need for significant new thermal plant to cover this shortfall. In this case 7GW of new CCGT would be required.

In the Lower RES scenario, there is 3GW less wind generation in GB in 2016. However, this does not lead to any further requirement for new build as the contribution of this wind generation to system margin is sufficiently low not to require new plant.

In the event of higher demand growth than outlined, it is possible that further new thermal build may be required.

6.3.2 *What are returns on new thermal generation?*

To ensure a broadly consistent scenario, we have made three key assumptions. Firstly, plant that are committed in the next few years will be built irrespective of our scenario assumptions – thus the new build in 2010 is the same in all scenarios. Secondly, the system will never get tighter than two periods of lost energy on average – i.e. we maintain a system security standard. Thirdly, to achieve this, prices must be sufficiently high to incentivise new entry when required through capacity revenues of some kind. In practice we found that some OCGT build is required by 2030, and with existing assumptions these investments are not commercially viable.

It should be noted that the purpose of this study was not to investigate plant returns for investment purposes, and the figures below are only an indication given our assumptions for scenarios. Different input assumptions, particularly on commodity prices, will lead to different plant returns.

As discussed in Section 4.2.5, we assume plant returns between 8%-12% would be sufficient to encourage new entry.

The returns on different types of plant are shown in Table 26 below, for the Core, Capacity Payment, Lower Stretch and Carbon Drop scenarios.

In GB, the highest returns are to nuclear plant across all the scenarios. This is due to the absence of volume risk, which means that (unlike thermal plant) they are unlikely to have depressed load factors due to large volumes of wind. Nuclear benefits from high commodity prices, so our assumption of $70/bbl for Brent, $70/t for coal and 58p/therm for gas gives high returns to nuclear. Five years ago, $30/bbl oil prices would have been considered a typical long-term view – a return to a low priced oil world would affect nuclear returns considerably due to the exposure to commodity price risk.

Across all scenarios, coal and CCS coal do not make sufficient returns to permit new build in our modelling. Conventional coal returns vary from 1% to 7% across the years, whilst CCS coal from 4.8% to 6.5% – all well below the indicative threshold of 8% for required for investment. Conventional coal returns are held down due to the high capital costs of build and a carbon price of £35/tCO_2 in the Core, Capacity Payment and Lower Stretch scenarios. The Lower carbon price of £20/tCO_2 in the Carbon drop scenario improves returns for conventional coal, but only to 7%. Returns on CCS coal plant remain low due to the capital costs of new build – a carbon price of £35/tCO_2 is not sufficient to incentivise investment and they would require some element of subsidy to run.

Returns to CCGTs are highly variable in the Core scenario. Where new CCGT build is required – primarily in 2030, returns on plant rise sufficiently high to incentivise new build though the Value of capacity. In years where there are sufficient system margins, plant returns drop substantially. In 2016, given much tighter system margins, IRRs on CCGTs rise towards new entry levels.

The Capacity Payment scenario leads to a very different outcome with regards to plant returns in GB. A payment for availability means that OCGTs become profitable, as they are in all scenarios in the SEM. CCGT returns drop with a Capacity Payment, particularly from 2020 onwards, this is because wholesale prices fall with increasing volumes of baseload and wind generation whilst the payment from the capacity mechanism do not remunerate sufficiently to cover the shortfall.

Table 26 – IRRs in Core, Capacity Payment and Carbon drop scenarios

Core

GB

	2010	2015	2016	2020	2030
Nuclear	N/A	N/A	N/A	11.2%	11.8%
CCSCoal	N/A	N/A	N/A	6.4%	6.5%
Coal	N/A	N/A	3.6%	2.7%	3.9%
CCGT_F	5.0%	7.6%	8.2%	6.2%	9.4%
OCGT	<0	<0	<0	<0	<0

SEM

	2010	2015	2016	2020	2030
CCGT	N/A	8.1%	8.1%	7.0%	6.3%
CCSCoal	N/A	N/A	N/A	N/A	4.4%
Advanced GT	N/A	2.6%	3.6%	6.5%	6.7%
OCGT (Gasoil)	8.9%	9.2%	9.3%	8.6%	8.8%

Capacity Payment

GB

		2015	2016	2020	2030
Nuclear		N/A	N/A	11.2%	10.9%
CCSCoal		N/A	N/A	5.9%	4.8%
Coal		N/A	2.5%	1.7%	0.9%
CCGT_F		7.0%	6.8%	5.5%	4.6%
OCGT		7.9%	7.9%	7.8%	8.1%

SEM

		2015	2016	2020	2030
CCGT		4.9%	4.7%	3.7%	3.1%
CCSCoal		N/A	N/A	N/A	4.4%
Advanced GT		1.1%	2.0%	4.5%	4.9%
OCGT (Gasoil)		8.1%	8.1%	8.1%	8.3%

Lower RES

GB

	2010	2015	2016	2020	2030
Nuclear	N/A	N/A	N/A	11.6%	12.3%
CCSCoal	N/A	N/A	N/A	6.9%	6.9%
Coal	N/A	N/A	4.4%	3.1%	3.9%
CCGT_F	6.2%	9.1%	9.7%	6.5%	8.8%
OCGT	<0	<0	<0	<0	<0

SEM

	2010	2015	2016	2020	2030
CCGT	N/A	9.3%	9.2%	6.6%	5.6%
CCSCoal	N/A	N/A	N/A	N/A	5.5%
LMS100	N/A	1.2%	2.1%	4.6%	4.8%
OCGT (Gasoil)	8.8%	9.0%	9.1%	8.2%	8.4%

Carbon drop

GB

	2010	2015	2016	2020	2030
Nuclear	N/A	N/A	N/A	9.9%	10.6%
CCSCoal	N/A	N/A	N/A	4.8%	5.1%
Coal	N/A	N/A	6.8%	5.8%	7.0%
CCGT_F	4.5%	7.3%	7.7%	5.9%	9.4%
OCGT	<0	<0	<0	<0	<0

SEM

	2010	2015	2016	2020	2030
CCGT	N/A	7.2%	7.2%	5.9%	5.3%
CCSCoal	N/A	N/A	N/A	N/A	1.9%
LMS100	N/A	2.8%	3.7%	6.7%	6.9%
OCGT (Gasoil)	8.9%	9.2%	9.4%	8.7%	9.0%

IED scenario

GB

	2010	2015	2016	2020	2030
Nuclear	N/A	N/A	N/A	11.8%	11.2%
CCSCoal	N/A	N/A	N/A	7.1%	6.1%
Coal	N/A	N/A	4.5%	3.5%	3.2%
CCGT_F	6.7%	10.2%	11.1%	9.2%	8.0%
OCGT	<0	<0	<0	<0	<0

SEM

	2010	2015	2016	2020	2030
CCGT	N/A	8.9%	8.9%	8.3%	5.3%
CCSCoal	N/A	N/A	N/A	N/A	3.9%
LMS100	N/A	4.1%	5.2%	8.0%	6.0%
OCGT (Gasoil)	9.2%	9.6%	9.8%	9.4%	8.6%

IRRs are pre-tax real. Returns of between 8%-12% are considered high enough to encourage investment. Tables exclude results for 2025 – these can be found in the Appendices. Capacity Payment scenario was not run for 2010 as a change to the market design could not be implemented by 2010. IRRs calculated assuming linear interpolation between modelled years.

In the SEM, there is a much greater consistency of outcome between scenarios due to the presence of the CPM. Thus returns to OCGT peaking plant remain above 8% in all scenarios and all years and are stable between 8-9%. This is because the vast majority of OCGT revenue comes from the Capacity Payment rather than varying wholesale prices since these plant run at very low load factors.

Returns to CCGTs vary, and in particular are affected by the GB market. Hence if the GB market remains with the current BETTA market arrangements, returns in the SEM are high as a result of high wholesale prices 'imported' from GB – typically between 7% in lower years and 9% in higher years. The Lower RES scenario leads to the best returns, due to high GB prices and high load factors for CCGTs given less renewables coming online. However, the implementation of a CPM in GB leads to Irish CCGT revenues falling sharply – to between 3-5%. This is because GB wholesale prices become much lower, keeping Irish prices low and hence depressing CCGT revenues.

Building advanced OCGTs in the SEM does not lead to sufficiently high returns to make them the main new entrant. Although they run at higher load factors than older OCGT designs due to higher efficiencies, their higher capital costs mean that returns remain low.

6.3.3 How important could the LCPD and IED emissions legislation be to the outcome?

The implications of the LCPD on existing plant are reasonably certain – in 2016, 10GW of coal and oil-fired plant that has not fitted FGD will have to close. Much of this may have already closed due to having exhausted their maximum of 20,000 hours running between 2009 and the end of 2016. If demand grows at the low rates outlined in the Core scenario of between zero and 0.5%, and currently committed new plant are built along with the renewables assumed for 2016, the Core scenario suggests that there is no pressing need for new plant to be built to meet the 2016 date. However, if demand grows at a greater rate or renewables at a slower rate it is likely that new plant will be required.

The IED, in its strictest reading, may have a greater effect on plant closures than the LCPD, with 5GW of coal and 8GW of CCGTs having to close by 2020, in addition to the LCPD closures. With a further requirement for new build, prices are high not only for 2016 but also for 2020, leading to higher prices for a longer period and thus higher returns on CCGTs, as shown in Table 26 above. The IED closes plant that is running at extremely low load factors (<5%) owing to increasing volumes of wind generation on the system.

6.4 Wind revenue

6.4.1 To what extent is wind revenue cannibalisation a problem?

Wind revenue cannibalisation describes the situation when generation from the wind is having a direct effect on prices. With high volumes of wind generation, prices are pushed downwards – hence wind generators capture lower prices. However, when there is low wind generation, prices are high – so wind farms do not capture high prices fully. This issue is termed 'cannibalisation' as wind is cannibalising its own revenue streams.

Figure 108 shows the extent of wind revenue cannibalisation in GB in the Core scenario. The black line shows the average price captured by a wind generator (annual revenue/annual generation) whilst the red line shows the TWA wholesale price[36]. In 2010, the wind capture price is higher than the TWA price – as a result of more wind generation in winter months when wholesale prices are higher. By 2016, this reverses, with wind capturing £5/MWh less than the TWA price, as increasing volumes of wind generation affect peak prices in particular. By 2030, wind captures £13/MWh less than market prices – a significant drop.

In the SEM, as shown in Figure 109, the effect of wind revenue cannibalisation is similar. In 2010, wind earns above the TWA price as in GB, but by 2020 this has dropped to

[36] Time weighted average price is the simple average of all hourly prices

£5/MWh (€5.5/MWh) below, and by 2030 the gap is £12/MWh. It is surprising that the effect in the SEM is not greater than in GB as the installed wind capacity is much greater. The reason is that the SEM is heavily interconnected to GB and GB price spikes and dips have a lower correlation to wind generation in Ireland.

Figure 108 – Wind revenue capture price in GB in Core scenario

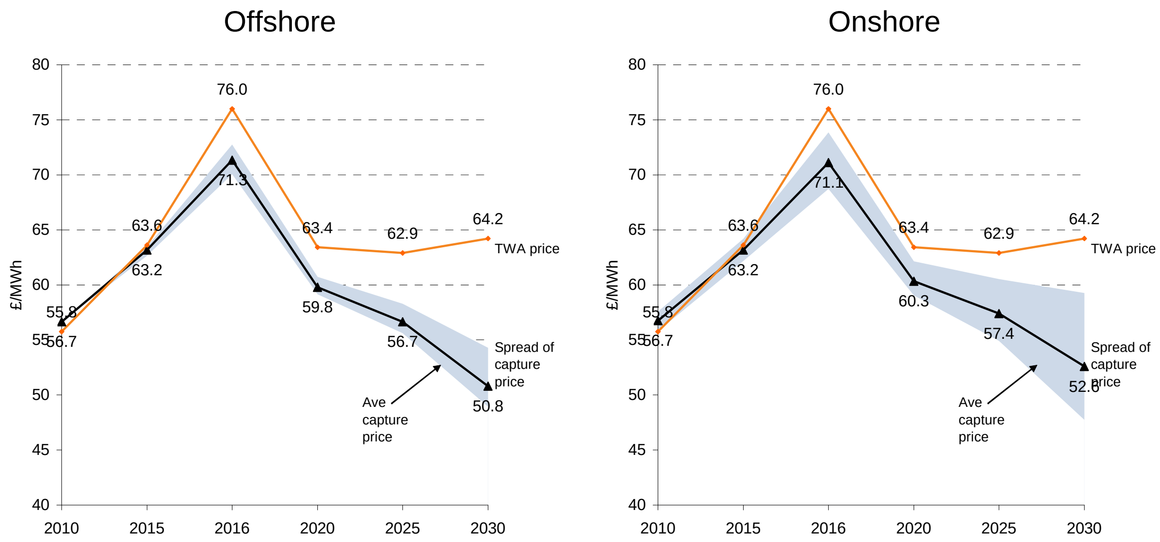


Figure 109 – Wind revenue capture price in the SEM

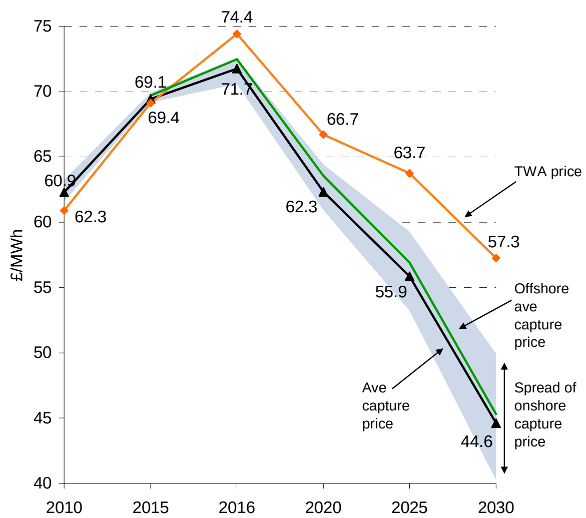


Figure 110 shows how wind revenue in different locations varies in 2030 in the Core scenario. There is a spread (also shown as the blue band in Figure 108 and Figure 109) between locations in GB of £12/MWh with the highest revenue location in Stornoway (north Scotland) and the lowest in Rhyl on the north-Wales coast, whilst in the SEM it is £10/MWh. It should be noted that this analysis refers to the capture price rather than total revenue – a location with high wind speeds may have a lower capture price but a higher overall revenue due to generating a greater volume of energy. It is notable that offshore locations tend to have lower capture prices than average despite much higher generation – this appears to be due to correlation.

Thus in a market with high wind penetration, it is not only the average wind speed at a given site that is important, but also the lack of correlation with other wind generation across the rest of the country.

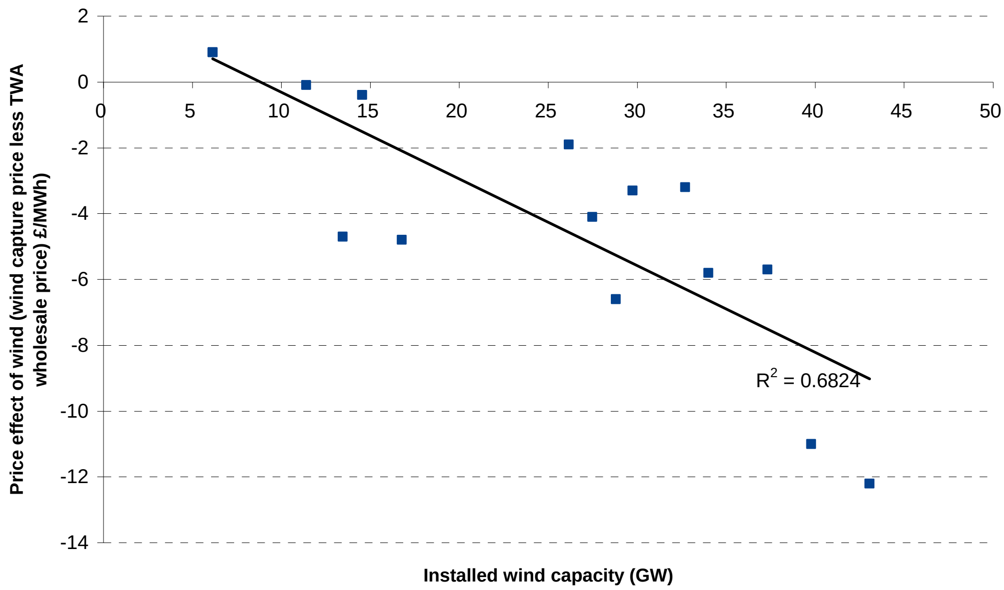
Figure 110 – Wind revenue capture price in 2030 by location

Capture price (£/MWh):

45 50 55 60 65

An approximate relationship can be established between the amount of installed capacity and the discount between the TWA price and the capture price of wind generation. Figure 111 shows this relationship for the GB market for three of the scenarios we have examined – the Core, Lower RES and Offshore Growth scenarios. There is an approximate relationship between the amount of wind capacity in the GB market and the discount to TWA prices that wind generation obtains. With 10GW installed, wind captures approximately the TWA price. For every further 1GW installed, wind capture prices drop £0.25/MWh below the TWA price. It is not clear that the relationship is linear, and other factors may change the relationship.

Figure 111 – Wind revenue capture price compared to wind generation in GB



Data points are from Core, Offshore growth and Lower RES scenarios.

Figure 112 – Wind capture prices for a range of locations and scenarios in 2030

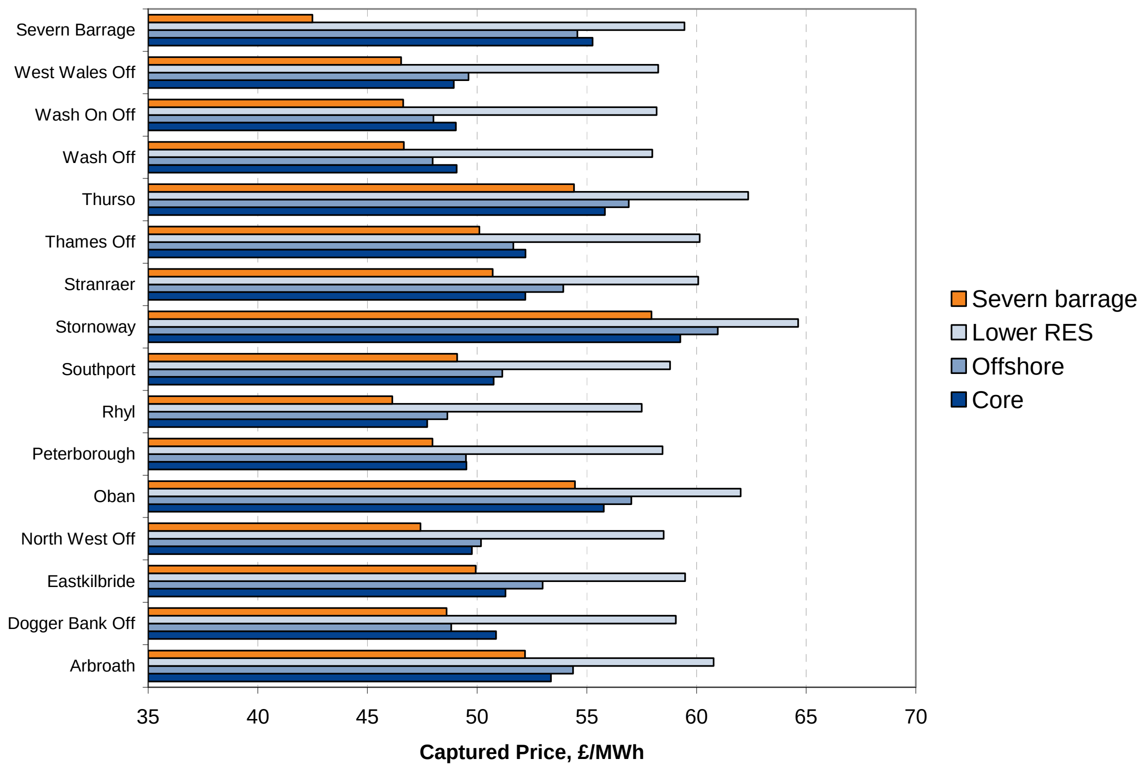


Figure 112 compares the wind capture prices for a range of the larger wind sites and the Severn Barrage. The captured prices broadly follow the expected trend, as outlined below.

- In the Severn Barrage scenario, with a large barrage, the captured price of the Severn Barrage is particularly low – as it depresses its own revenue in a similar manner to wind revenue cannibalisation.
- In the Severn Barrage scenario all wind sites have a significantly lower capture price. This is because, with more low cost generation, at times when it is windy the SMP is more likely to collapse to zero (or less). Note that more nuclear capacity would probably have the same effect.
- All captured prices are much higher in the Lower RES scenario due to the reduced wind capacity.
- In the Offshore scenario, (which has a greater concentration of wind off the East Coast of England in the Dogger Bank and the Wash), Dogger Bank and the Wash (including Wash onshore) have a significantly lower capture price than in the Core scenario. The reason for this is that, with the concentrated distribution of wind, when it is windy in one of the sites, there will normally be quite a lot of wind overall. Thames Offshore has a marginally lower capture price in the offshore scenario, compared to the Core, but other sites have a higher capture price.

6.4.2 *How much is wind output is de-loaded?*

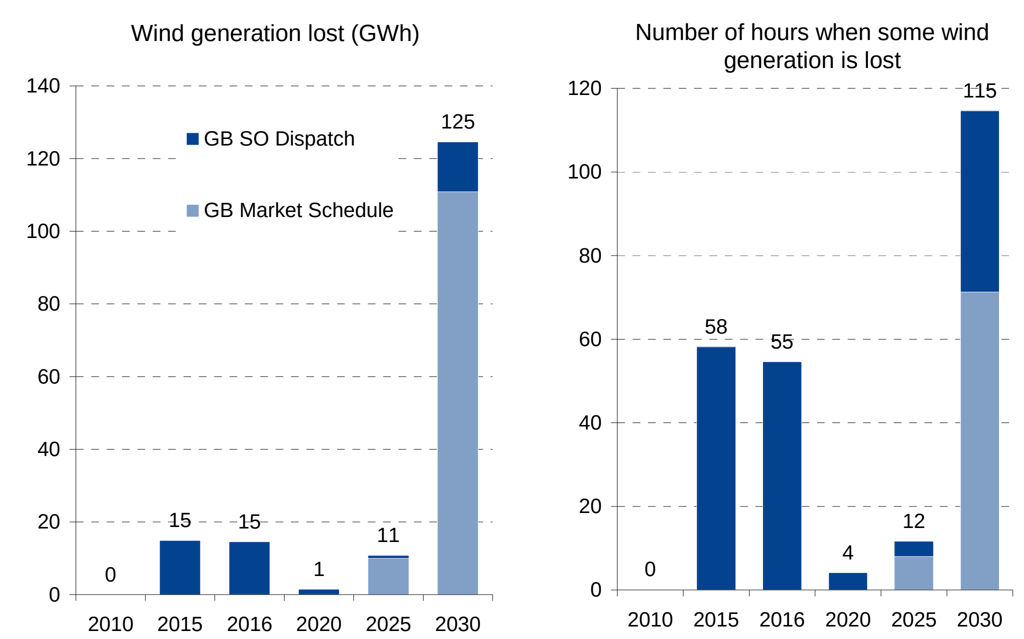
In a market where there is a lot of installed wind capacity, it may be necessary to reduce wind output below what is possible for a number of reasons ('de-loaded'). Firstly, if wind generation exceeds demand and the excess cannot be exported. Secondly, if it is cheaper to de-load wind rather than turn off a power plant for a short period of time – for example it may be more economic to reduce wind output for a couple of hours than switch off a large coal or nuclear station and then restart it. Thirdly, if system operation constraints with reserve or response mean that wind has to be curtailed to keep sufficient thermal plant on the system to meet reserve constraints. Finally if transmission constraints mean that wind generation in certain region has to be constrained off. The first three of these factors are modelled within Zephyr, with the transmission effects modelled in part with constraints between the model's four zone.

Figure 113 shows how much wind generation is de-loaded in GB in the Core scenario, with the light blue bars showing how much wind is lost in the Market Schedule due to economic reasons, and the dark blue the amount lost in the SO Dispatch due to System Operator restrictions on reserve/response or transmission constraints (for our four zones only).

Until 2025, almost no wind output is reduced due to Market Schedule reasons. By 2025, there are 12 hours in the year when this happens, and by 2030 there are 115 hours on average.

In 2015 and 2016, due to the system becoming tighter, there is some constraining and curtailing of wind due to Scotland/England transmission constraints. With these eased by 2020, there is very little wind that is constrained off until 2030.

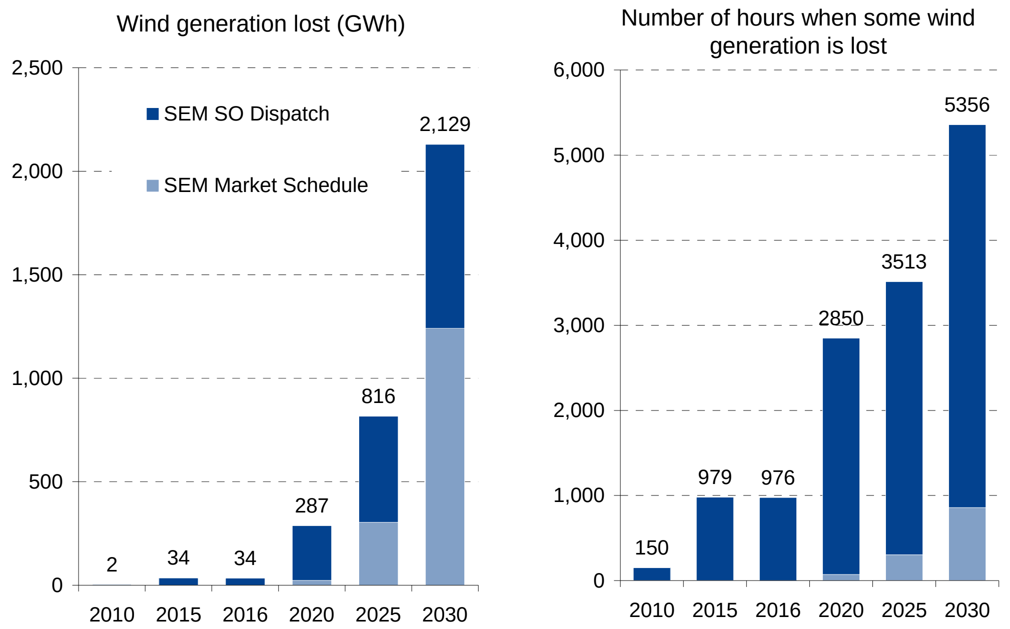
Figure 113 – Wind generation loss in GB in the Core scenario



Market Schedule does not include reserve/response or Scotland/England transmission constraints. SO Dispatch includes effect of both.

In the SEM, there is a significantly different picture due to the much smaller market, tighter reserve and response provision and greater interconnection constraints to GB. In 2015 and 2016, no wind is de-loaded in the Market Schedule and although there are almost 1000 hours when wind is de-loaded, the volumes tend to be very small. By 2020, the volume of wind generation lost starts to increase to 287GWh with about a quarter of the year with periods of limited wind de-loading. By 2030, this has increased substantially, with over 2TWh of wind de-loaded over 5000 hours. Much of this is due to the sheer volume of installed capacity – in the Market Schedule about 1.2TWh of wind is de-loaded for economic reasons or an excess of wind generation compared to demand and available export capacity[37]. However, a further 1TWh is due to north/south transmission constraints and reserve/response issues.

Figure 114 – Wind generation lost in the SEM in the Core scenario



Market Schedule does not include reserve/response or NI/ROI transmission constraints. SO Dispatch includes effect of both. Periods are hours.

The issue of wind de-loading is driven by the volume of wind generation installed. Thus in the Lower RES scenario, where installed capacity reaches 29GW in 2030 in GB and 5GW in the SEM, there is barely any wind de-loading in either GB or in the SEM. Increasing the amount of wind offshore – particularly in the North Sea – does increase the amount of wind de-loaded, as the wind generation becomes somewhat more correlated. In GB this increases the volume of wind shed from 111GWh in the Core scenario to 153GWh. The SEM experiences a similar increase with de-loading increasing from 1.2TWh to 1.9TWh.

A large Severn Barrage also makes a substantial increase in the wind de-loading, due to an extra 10GW of very low priced generation available twice a day. Since the Severn Barrage is assumed to bid in with -2ROCs (about -£70/MWh), it displaces onshore and offshore wind generation (which bid at -1 and -1.5 ROCs respectively). Thus wind de-

37 Given the small nature of the Irish market and the limited interconnection, it suffers from a phenomenon we have avoided calling ‘trapped wind’.

loading increases to 500GWh in GB in 2030 from 111GWh in the Core scenario. The Severn Barrage is sufficiently large that it also affects the SEM too, raising wind de-loaded from 1.2TWh in the Core scenario to 1.7TWh.

Figure 115 – Wind de-loaded in different scenarios in GB (Market Schedule only)

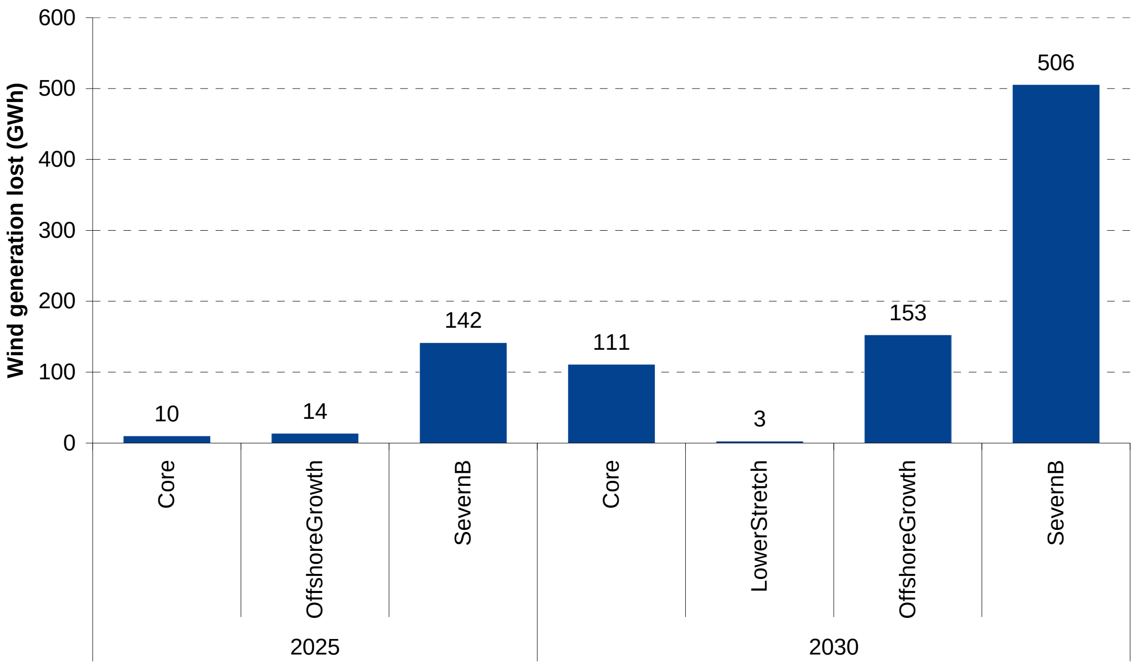
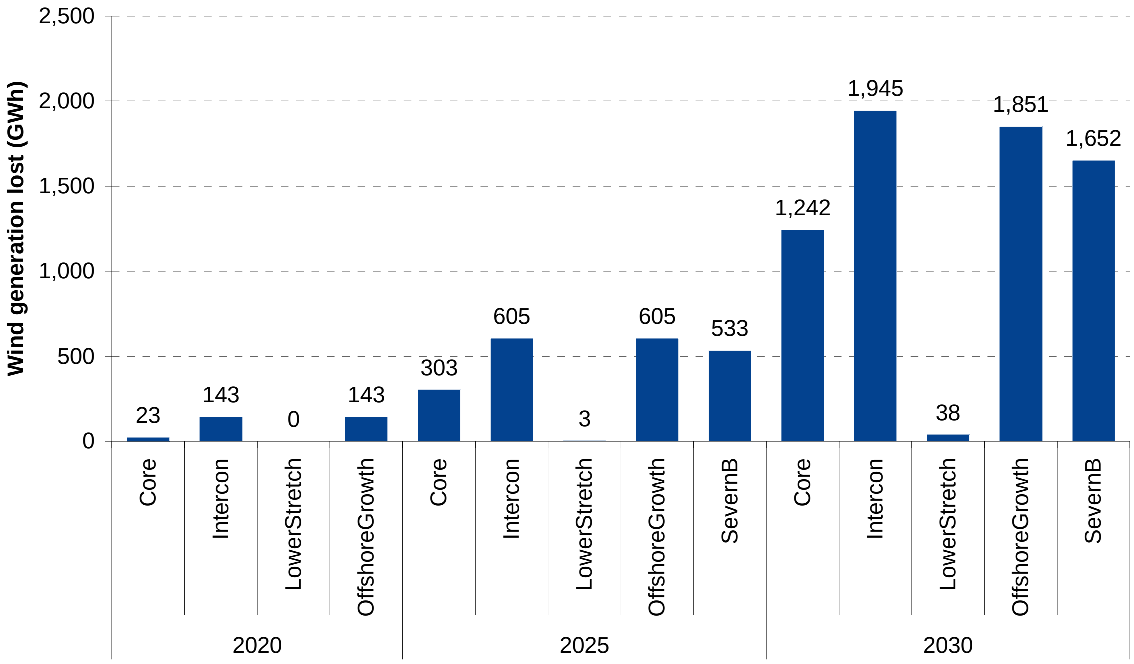


Figure 116 – Wind de-loaded in different scenarios in the SEM (Market Schedule only)



6.5 Reserve and response

For the Core scenario and other key cases, we have examined a 'Market Schedule' run and a 'System Operator Dispatch (SO Dispatch)' run. The Market Schedule run derives prices and the operation of plant without transmission and reserve/response constraints – this represents an hour or day-ahead market. Where of interest, we run a SO Dispatch simulation[38], which accounts for reserve and response constraints as well as transmission constraints between NI/RoI and E&W/Scotland – representing some of what a System Operator would do to ensure the system remained stable. The reserve and response constraints will cause the System Operator to redispatch plant to ensure enough are running, part-loaded or ready to run to ensure that the SO can meet potential shortfalls on generation.

The reserve and response constraints modelled are:

- Inertia (SEM only). A requirement for a minimum number of thermal units generating at one time.
- Low frequency response. This is the capability to respond to a drop in system frequency typically caused by a trip (forced outage) of anther unit.
- High frequency response. This is the capability to respond to a rise in system frequency caused by demand tripping off the system.

38 We have only run the SO Dispatch simulation for the Core scenario

- Four hour reserve. This covers requirements for unforeseen increases in generation requirements, due to uncertainties in demand and supply forecasting.

This section examines the results of the SO Dispatch runs, to investigate the implications of the reserve and response constraints:

- How often are the various constraints binding, or unable to be met?
- What are the implications of higher reserve requirements (due to increased wind) on warming[39]?
- What effect do reserve and response requirements have on plant operating patterns?
- What effect do the transmission constraints have on plant operating patterns (including renewables)?

6.5.1 What is the effect of reserve and response constraints on plant load factors?

Table 27 and Table 28 compare plant load factors in the Market Schedule and System Operator Dispatch runs. In GB, there is little difference in plant load factors, but the trend is for the load factor of low load factor plant to rise slightly, and the load factor of high load factor plant to fall slightly. In the SEM there is a much larger change in plant load factors. Apart from biomass, the load factors of all technologies are higher in the SO Dispatch run, due to lower net imports from GB and more de-loaded wind. There are particularly large increases in the load factors of peaking plant and coal plant, with the increase in peaking plant primarily due to the response constraints (discussed in more detail in the next section). Coal plants have a lower minimum stable generation and lower no-load costs than CCGTs, so are relatively good at running part-loaded. There is a particularly large increase in load factor for the Kilroot coal plant in Northern Ireland – this is due to the relative lack of wind capacity in Northern Ireland, combined with the transmission constraint between Republic of Ireland and Northern Ireland.

In GB pumped storage utilisation (amount of time spent pumping or generating) is significantly lower in the System Operator Dispatch run. This is because pumped storage provides low frequency response when it is neither generating nor pumping[40]. Although the volume of low frequency response capability from pumped storage is highest when it is pumping, this is typically overnight when low frequency response is not a significant factor. There is a drop in the pumped storage load factor in the SO Dispatch run in 2020 – this is a result of a higher low frequency requirement due to the commissioning of EPRs. In the Market Schedule and SO Dispatch runs there is some increase of pumped storage utilisation from 2020 to 2030 – this is a result of increasing price volatility due to increased wind (and to some extent nuclear and CCS coal).

In SEM pumped storage utilisation is higher in the SO Dispatch case. This is probably because the low frequency response contribution of pumped storage is highest when pumping (far higher than when not pumping or generating), and in SEM (unlike in GB) low frequency response remains an issue overnight.

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[39] Effectively keeping power plants in a state where they are capable of generating given four hours notice. In the case of the four hour requirement it is how often the requirement is unable to be met (through insufficient installed capacity)

[40] In reality it would need to be synchronised (generating at a minimum level) but this has not been modelled.

Table 27 – Comparison of load factors in Market Schedule and SO Dispatch (GB)

Market Schedule

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	68%	68%	67%	66%
CCGT_SEM	58%	41%	46%	28%	25%	18%
CCSCoal	N/A	N/A	N/A	N/A	N/A	74%
CHP	86%	86%	86%	81%	74%	59%
Coal	83%	63%	65%	49%	44%	35%
Gas_steam	2%	2%	10%	2%	2%	2%
OCGT_Gas	0%	0%	3%	0%	0%	0%
OCGT_Gasoil	0%	0%	1%	0%	0%	0%
Advanced OCG	N/A	N/A	N/A	4%	5%	4%
Oil_steam	2%	1%	6%	1%	2%	1%
Pumped Storag	6%	5%	8%	7%	8%	10%

System Operator Dispatch

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	67%	66%	66%	64%
CCGT_SEM	59%	44%	49%	32%	29%	20%
CCSCoal	N/A	N/A	N/A	N/A	N/A	76%
CHP	84%	83%	83%	78%	73%	59%
Coal	79%	67%	70%	60%	57%	49%
Gas_steam	4%	2%	11%	2%	3%	2%
OCGT_Gas	1%	0%	3%	0%	0%	0%
OCGT_Gasoil	0%	0%	1%	0%	1%	3%
Advanced OCG	N/A	N/A	N/A	8%	11%	12%
Oil_steam	2%	1%	7%	3%	6%	8%
Pumped Storag	12%	11%	14%	12%	13%	13%

Difference

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	-0.7%	-1.5%	-1.6%	-1.5%
CCGT_SEM	0.6%	3.2%	2.1%	3.3%	3.8%	2.2%
CCSCoal	N/A	N/A	N/A	N/A	N/A	2.6%
CHP	-1.7%	-3.0%	-2.5%	-2.3%	-1.4%	0.2%
Coal	-3.6%	4.4%	4.3%	11.9%	13.3%	13.6%
Gas_steam	1.4%	0.4%	1.0%	0.4%	0.5%	0.6%
OCGT_Gas	0.5%	0.1%	0.8%	0.1%	0.1%	0.0%
OCGT_Gasoil	0.0%	0.0%	0.1%	0.2%	0.7%	2.5%
Advanced OCG	N/A	N/A	N/A	4.1%	6.1%	8.0%
Oil_steam	0.8%	0.2%	0.5%	2.0%	4.1%	7.2%
Pumped Storag	5.3%	5.7%	5.9%	5.2%	4.8%	3.2%

Table 28 – Comparison of load factors in Market Schedule and SO Dispatch (SEM)

Market Schedule

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	68%	68%	67%	66%
CCGT_SEM	58%	41%	46%	28%	25%	18%
CCSCoal	N/A	N/A	N/A	N/A	N/A	74%
CHP	86%	86%	86%	81%	74%	59%
Coal	83%	63%	65%	49%	44%	35%
Gas_steam	2%	2%	10%	2%	2%	2%
OCGT_Gas	0%	0%	3%	0%	0%	0%
OCGT_Gasoil	0%	0%	1%	0%	0%	0%
Advanced OCG	N/A	N/A	N/A	4%	5%	4%
Oil_steam	2%	1%	6%	1%	2%	1%
Pumped Storag	6%	5%	8%	7%	8%	10%

System Operator Dispatch

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	67%	66%	66%	64%
CCGT_SEM	59%	44%	49%	32%	29%	20%
CCSCoal	N/A	N/A	N/A	N/A	N/A	76%
CHP	84%	83%	83%	78%	73%	59%
Coal	79%	67%	70%	60%	57%	49%
Gas_steam	4%	2%	11%	2%	3%	2%
OCGT_Gas	1%	0%	3%	0%	0%	0%
OCGT_Gasoil	0%	0%	1%	0%	1%	3%
Advanced OCG	N/A	N/A	N/A	8%	11%	12%
Oil_steam	2%	1%	7%	3%	6%	8%
Pumped Storag	12%	11%	14%	12%	13%	13%

Difference

	2010	2015	2016	2020	2025	2030
Biomass	N/A	N/A	-0.7%	-1.5%	-1.6%	-1.5%
CCGT_SEM	0.6%	3.2%	2.1%	3.3%	3.8%	2.2%
CCSCoal	N/A	N/A	N/A	N/A	N/A	2.6%
CHP	-1.7%	-3.0%	-2.5%	-2.3%	-1.4%	0.2%
Coal	-3.6%	4.4%	4.3%	11.9%	13.3%	13.6%
Gas_steam	1.4%	0.4%	1.0%	0.4%	0.5%	0.6%
OCGT_Gas	0.5%	0.1%	0.8%	0.1%	0.1%	0.0%
OCGT_Gasoil	0.0%	0.0%	0.1%	0.2%	0.7%	2.5%
Advanced OCG	N/A	N/A	N/A	4.1%	6.1%	8.0%
Oil_steam	0.8%	0.2%	0.5%	2.0%	4.1%	7.2%
Pumped Storag	5.3%	5.7%	5.9%	5.2%	4.8%	3.2%

6.5.2 How binding are frequency and inertia constraints?

Figure 117 shows how often the reserve and response constraints bind (or in the case of the 4 hour requirement are not met). Note that the four hour figures are reserve and response requirements combined.

Frequency

In GB, initially the low frequency requirement binds between 20% and 30% of the time. There are a number of reasons for the fall from 2010 to 2016, but the main factor is that the Market Schedule run uses less pumped storage output in 2016 than in 2010 – this means that less changes to pumped storage and power plant operating patterns are required to provide response. In 2020 there is a big increase in how often the constraint binds: this is due to EPRs being commissioned which raises the requirement by 460MW. The reason a 460MW change in the requirement makes so much difference is that the pre-EPR requirement was always met when there was no pumped storage generation (since in this state pumped storage provides at least 900MW), whereas this is no longer the case post-EPR (also see Reserve and Response in Appendices).

In the SEM the low frequency constraint binds much more often. There are three main reasons for this: firstly, the requirement is far higher relative to the size of the market; secondly, for each thermal unit only 5-10% (unit dependent) of the capacity can count towards the requirement – not the full headroom; and finally, there are much more stringent limitations on the amount of response that can be provided by pumped storage.

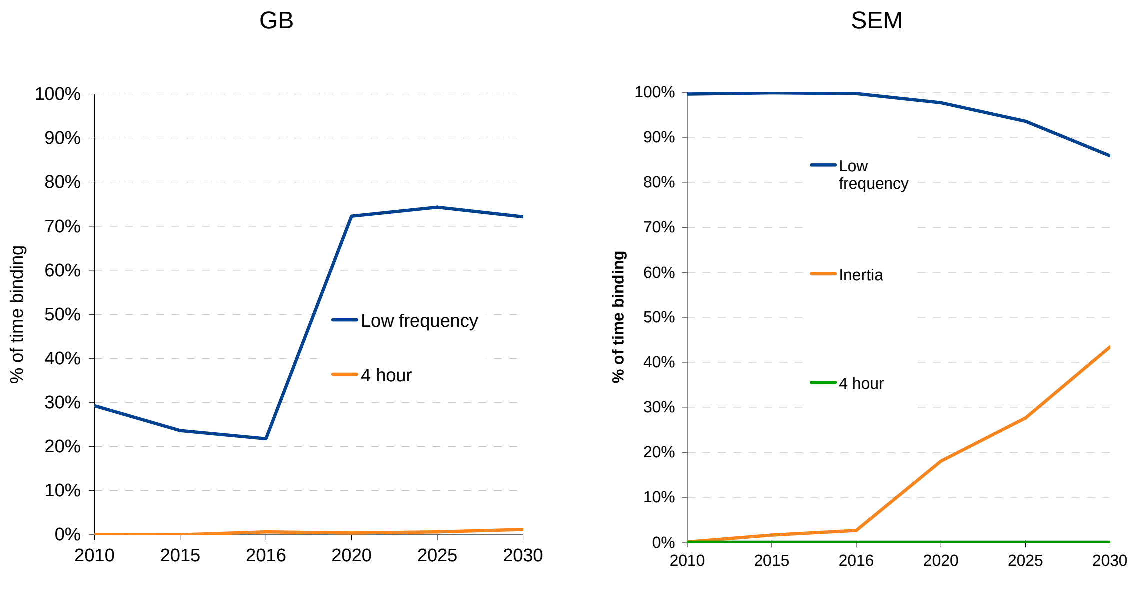
The limited headroom of 5-10% of capacity is particularly important at night; since, when demand is lower, the total volume of capacity running will be lower. As the wind penetration increases, the constraint becomes less binding. This is because 30% of de-loaded wind can provide response. For example, in 2030, in 87% of the periods with low frequency response not binding, there was more than 300MW of de-loaded wind, compared with 16% of periods with more than 300MW de-loaded wind overall.

Inertia constraint (SEM only)

As wind penetration increases the inertia constraint for the SEM becomes far more binding. There are three main reasons for this:

- As wind generation increases, for a given hour less thermal generation will be required. Consequently, there would be a smaller volume of thermal capacity generating (and without response requirements probably less units). Note this effect (on its own) would make the low frequency constraint more binding.
- With even higher wind capacity built on the system, wind will start being de-loaded more frequently – this reduces the requirement for thermal generation to provide low frequency response, so inertia starts being the main response issue (a higher frequency requirement will typically lead to more units generating).
- By 2030, there is a large (450MW) CCS coal unit commissioned in Northern Ireland. Apart from renewables, this unit is likely to be top of the Irish merit order (i.e. lowest variable cost), but despite its size, it is still is only one unit as far as the inertia constraint is concerned. Combined with point i), this has a large effect on the number of units generating.

Figure 117 – How often reserve and response constraints bind or are not met

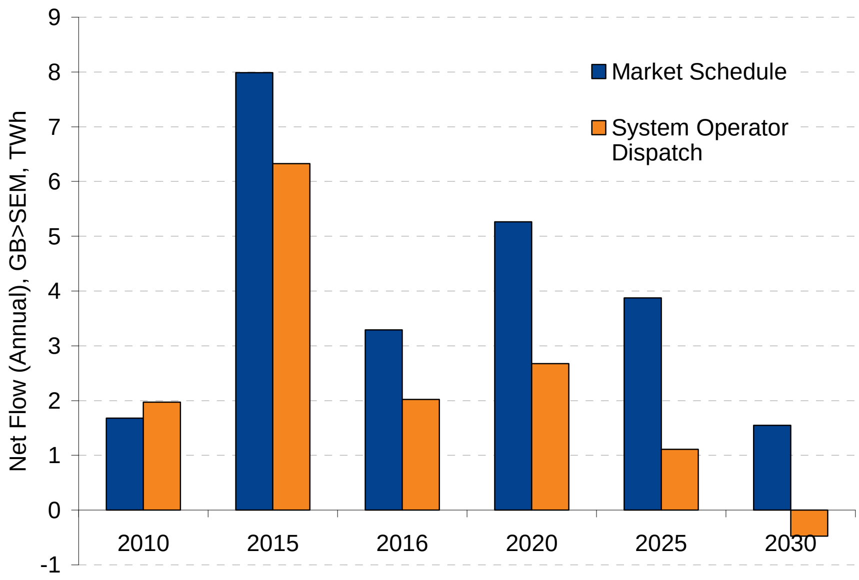


It is interesting to consider the ways in which plant dispatch is modified such that the inertia constraints in the SEM can be met There are a number of ways plant dispatch could be modified, all of which do actually occur at various times:

- Run power plants with a smaller capacity. This has the disadvantage that these plants may be considerably less efficient than the larger plants they are displacing – as a result start-up costs may increase, as the small plants will be run for as short a period as possible.
- Increase net exports from SEM to E&W. This will increase the volume of generation in the SEM, so naturally lead to more units being on (so more system inertia). The cost of this approach will be determined by the shapes of the relevant parts of the two supply curves, and whether, without the inertia constraint the interconnector would have been constrained. It should however be noted that the SEM low frequency constraint may also lead to more flows from SEM to E&W[41].
- De-load more wind in the SEM – this will lead to more thermal generation[42], so more system inertia. De-loading significant amounts of wind may result in a significant increase in system costs.

Figure 118 compares the GB to SEM interconnector flows in the Market Schedule and SO Dispatch runs. As expected, there are more flows from SEM (on a net basis) in the SO Dispatch run. It is however difficult to say how much this is due to the inertia constraint.

Figure 118 – Comparison of GB to SEM interconnector flows in Market Schedule and SO Dispatch runs



41 The limitation that each thermal plant can only contribute 5-10% of its capacity may lead to more capacity being on in SEM than would otherwise be the case.

42 It will actually lead to more thermal capacity on, but having this extra capacity on will tend to reduce the volume of capacity on in GB, so there will also be more generation in SEM.

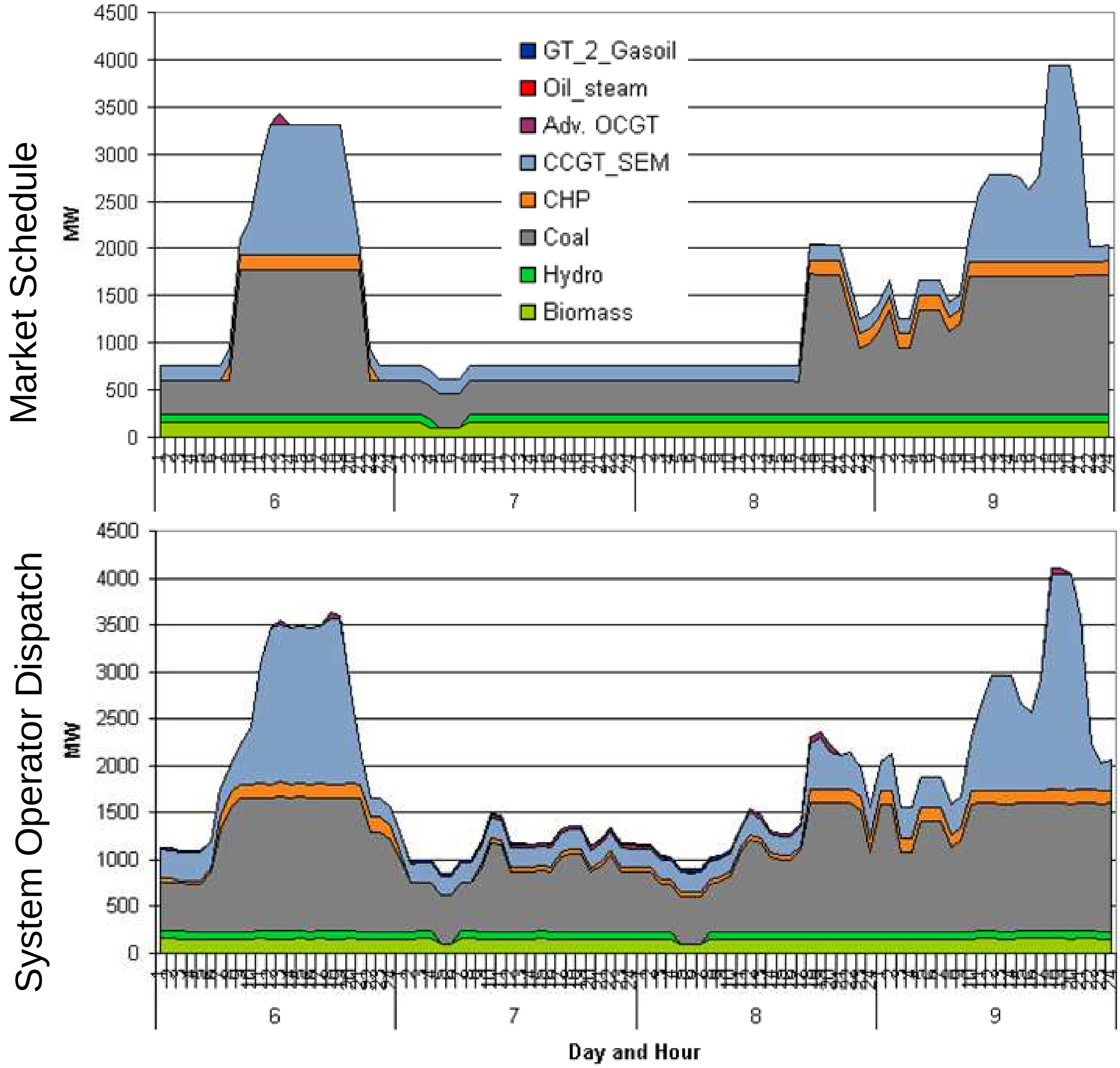
6.5.3 How does reserve and response change operation of plant?

Figure 119 compares the plant dispatch in the Market Schedule and SO Dispatch runs for the SEM, whilst Figure 120 shows when the low frequency and inertia constraints bind for the same period in the SEM. We see that one or both are binding all the time. On days 6 and 9 the inertia constraint is not binding during the day (but is binding some of the time at night). On days 7 and 8 the inertia constraint is binding much of the time, and there are (partly as a consequence) a number of periods where the low frequency constraint does not bind. Day 8 and 9 are non-business days.

On days 6 and 9 the main changes in dispatch are that there is a little more use of peakers (to help meet the low frequency response requirement) and higher total generation (particularly at night). As outlined above having more capacity on (which here leads to more output) helps meet the overnight low frequency requirement due to plants being limited to providing 5-10% of their capacity as reserve. Out at the start of day 6 there is a 400MW difference in thermal output between the Market Schedule and SO Dispatch runs, a difference of about 50%.

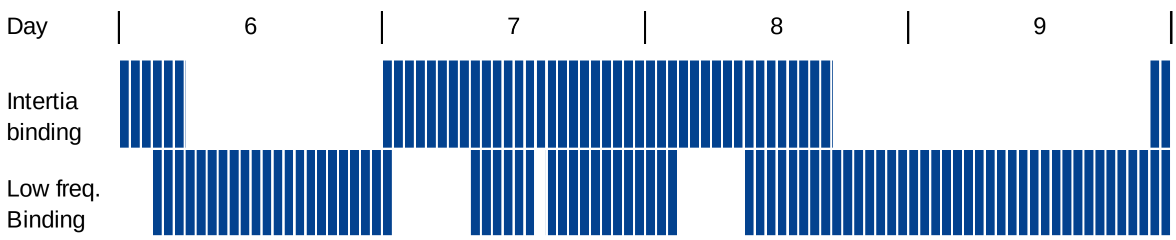
On days 7 and 8, with the inertia constraint binding much of the time, and the low frequency response requirement on thermal capacity falling due to de-loaded wind, there is a much larger change in output patterns. For period 10 on day 7, the total thermal generation increases from 700MW to 1500MW, more than doubling. Factors affecting the level of output include the level of demand net of wind and the residual response requirements (requirement on thermal plant). The mix of plant generating is strongly influenced by the inertia requirement. As well as CCGTs and coal plant, there are OCGTs and oil steam plant which primarily contribute to inertia, and an advanced OCGT, which contributes to low frequency response and inertia. OCGTs run more at night (when inertia is more of an issue) and Advanced OCGTs primarily during the day.

Figure 119 – Example of comparison of plant operation in Market Schedule and System Operator Dispatch Runs (SEM)



Comparison for days 6 – 9 in January 2020 for Monte Carlo 2000.
Comparison shows thermal plant (including non-intermittent renewables)

Figure 120 – When inertia and low frequency constraints bind



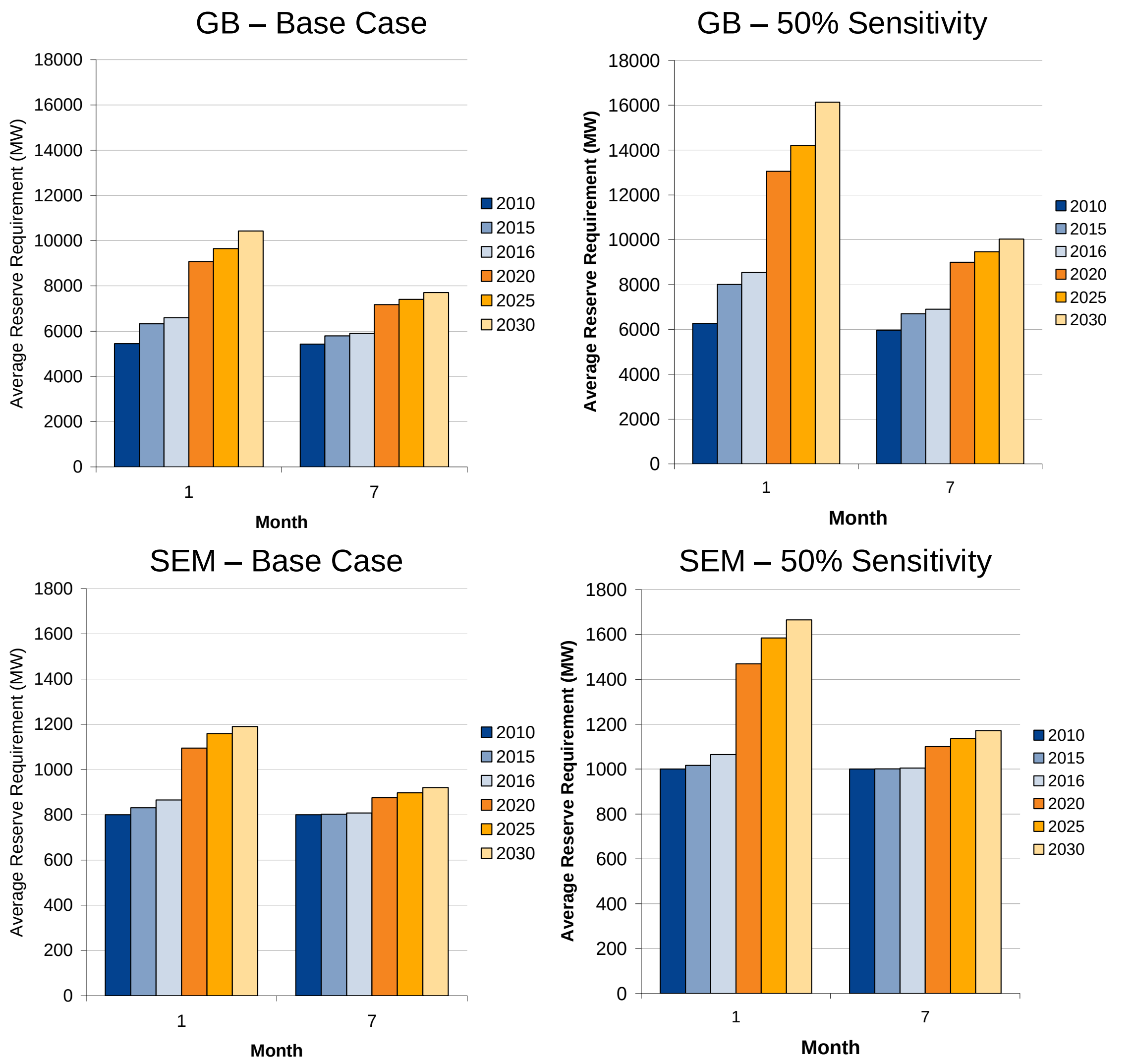
6.5.4 How important is wind forecasting to the 4-hour constraint?

The four-hour constraint covers plant that must be maintained in a state where they can be brought on within 4 hours to meet errors in forecasts of demand, wind generation or thermal plant availability. Thus the error in wind forecasting that the system operator plans for is taken into account – this does not represent the average error in wind generation forecasting, but the error that the system operator is planning for. We have used two assumptions – 25% of wind output (our base case) or a more conservative 50% of wind output. In these two cases the SO is planning for 25% or 50% of the forecast wind not to be available within 4 hours.[43]

The evolution of the 4-hour reserve requirement is shown in Figure 121. Unsurprisingly, the requirement increases over time as the volume of installed wind capacity increases. In the Base case (25% requirement), the requirement in GB rises from 500MW in 2010 to about 11GW in 2030, whilst in the SEM it rises from 800MW to 1600MW over the same period. Increasing the amount of reserve required for a wind error in forecasting of 50% significantly increases the required reserve, rising to 16GW in GB in 2030 and 1700MW in SEM in 2030.

43 In the SEM, the requirement with no wind was increased to 1000MW.

Figure 121 – Evolution of 4 hour reserve requirement (includes low frequency response requirement)



In the case of the four hour constraints, there is a small proportion of the time where they are either not met (due to not enough capacity), or are only met through increasing imports from Continental Europe beyond the level they would otherwise be. At all other times there is more than enough capacity available to meet the four hour requirement. In the SEM it is very rare for the 4 hour constraint not to be met.

Figure 122 shows how on what proportion of days the 4 hour constraint binds (or is not met) at some stage. The main driver is the capacity margins (if there is barely enough capacity to meet demand there clearly is not enough to meet the reserve requirement[44]), but increasing wind is also a factor. For GB, Figure 123 shows the size of the shortfall for

44 We may be slightly overstating this, since our availabilities include forced outages – but this is part of what the reserve was for; there is no need for enough capacity to meet forced outages and the reserve requirement separately.

those periods where the 4 hour reserve requirement cannot be met. Comparing 2016 and 2030, despite greater loss of load in 2016, there are more periods with more than 1.5GW of reserve unable to be met in 2030 in the base case – this is a consequence of the increased reserve requirements due to greater wind penetration. As expected, shortfalls are much larger with a 50% uncertainty factor.

In the SEM, Figure 124 gives the percentage of time with a given shortfall for the 50% sensitivity. There is a shortfall in a small number of periods, particularly in 2010, and this reduces rapidly due to the large increase in GB to SEM interconnection in 2015.

Figure 122 – Proportion of days on which the four hour constraint binds or is not met (GB)

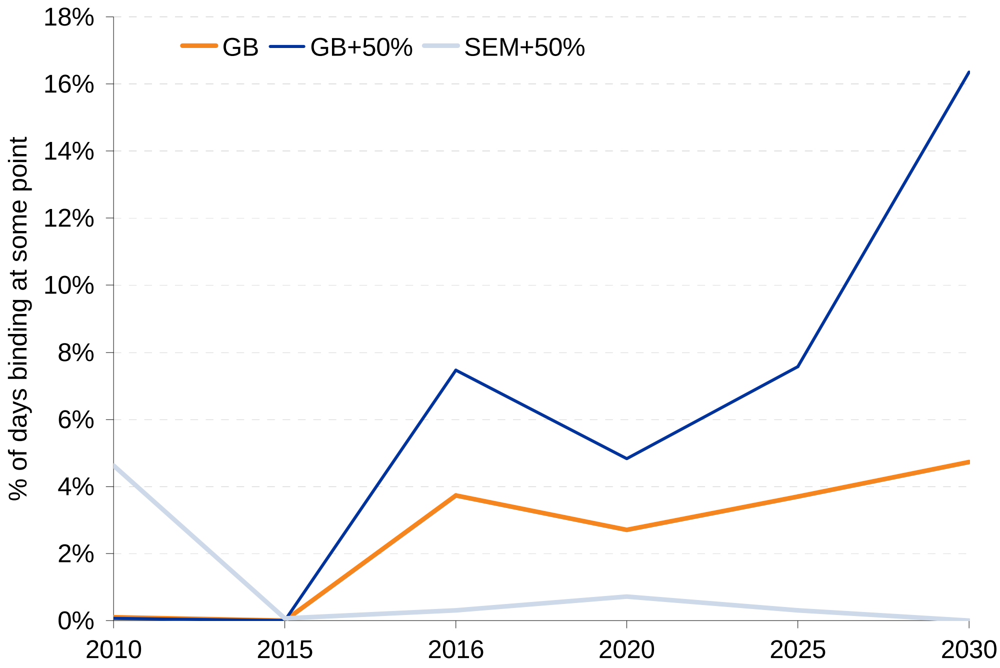


Figure 123 – Percentage of time with given reserve shortfall (GB)

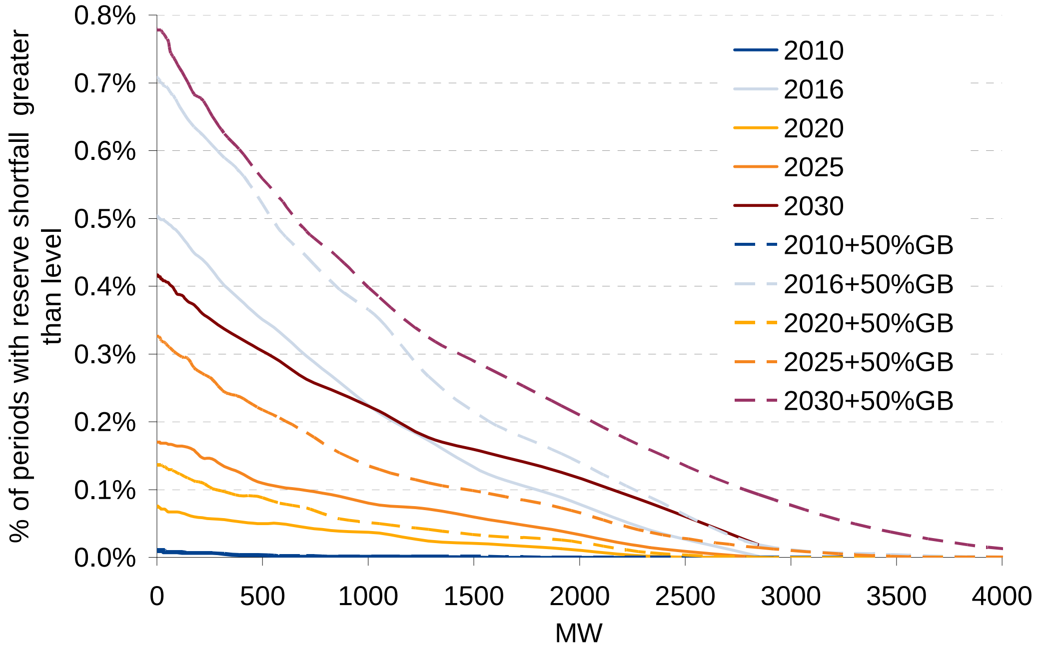
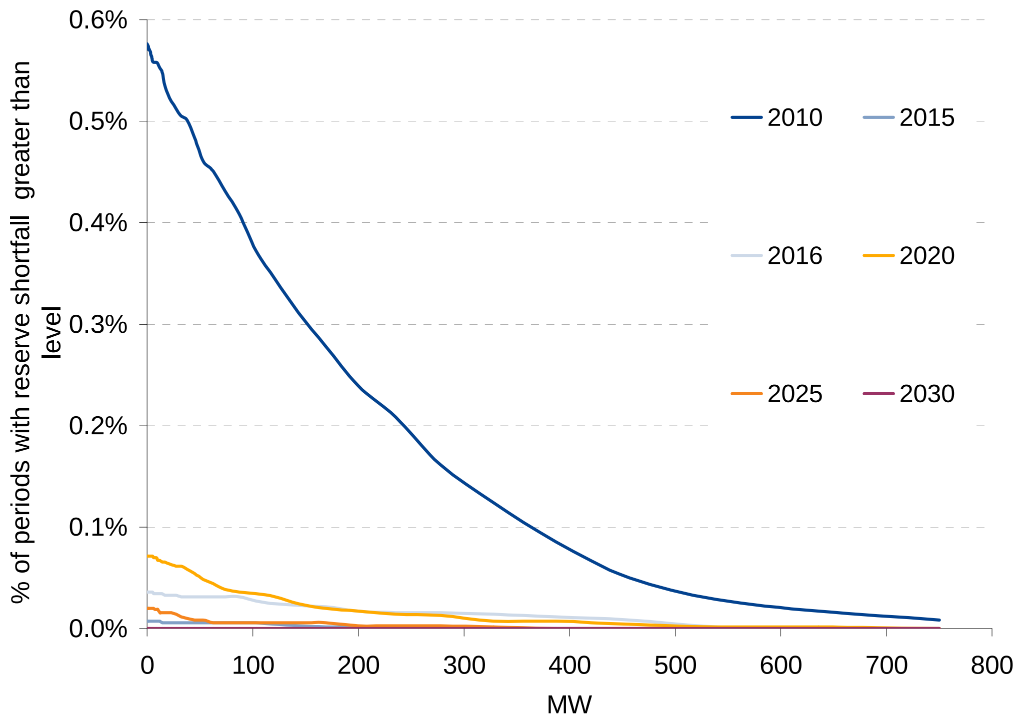


Figure 124 – Percentage of time with given reserve shortfall (SEM, 50% sensitivity)



6.5.5 What are the implications for warming?

The requirement for four-hour reserve shown in Figure 121 is the average in a January or July business day – on days when it is windy the requirement is higher, whereas when it is not windy the requirement is lower. The growth in reserve requirements means more capacity is required that is capable of generating, given four hours notice. This could be met by building more OCGTs (which can easily start within one hour from cold), or keeping other plant (e.g. coal, CCGTs) sufficiently warm that it can generate given four hours' notice.

Figure 125 shows the length of time that plant have been off which are required to provide four-hour reserve. In 2010, the average requirement of 6GW, almost 4GW is met from plant that is running or has a fast ramp rate such as pumped storage or OCGTs. The remaining 2GW is met from plant that needs to be kept in a state whereby it can be brought on rapidly – typically through keeping the plant warm by burning fuel. In GB there is an increase in the extent plant need to be kept warm for two main reasons. Firstly, the requirements for four-hour reserve increase, thus increasing the amount of warming required. Secondly, plant are running at lower load factors and hence are more likely to have been off for longer periods of time, particularly in periods with high wind generation. Finally, in GB, the market does not deliver peaking new entry – only baseload new entry. As a result, much of the requirement for four-hour reserve falls on baseload plant which would be cold except for warming contracts.

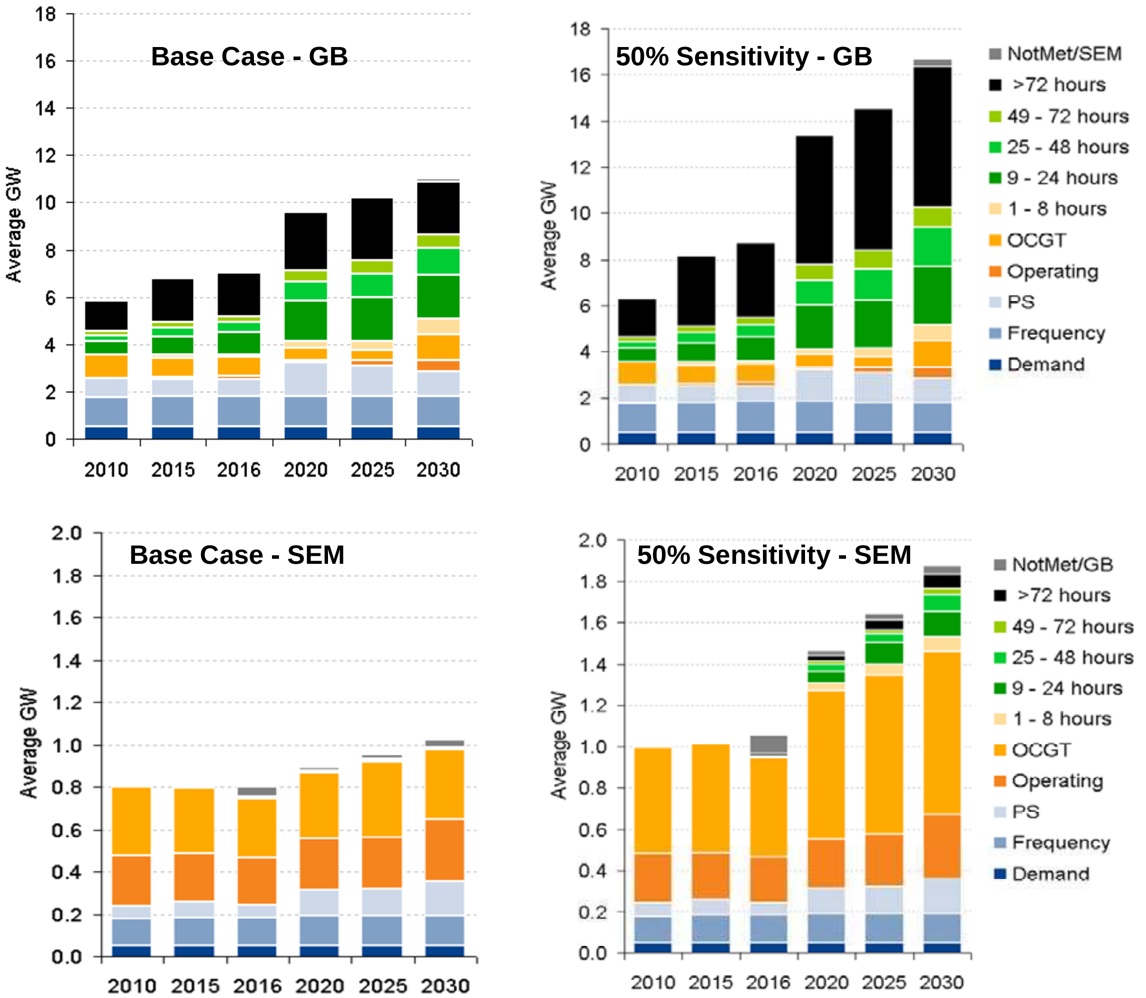
In the sensitivity where we require 50% of wind generation to be held as reserve, the requirement on cold plant rises even more sharply to 6GW by 2030. In the charts we do not differentiate by technology – it may be much cheaper to keep an oil steam plant warm than a CCGT for example, which would increase the effect of the increase.

In the SEM the four hour reserve constraint provides little problem in the 25% case, due to the relatively large number of OCGT plant that are built. Thus the requirement can be met without any warming of plant. In the 50% case, a small number of plant will be required to be kept warm, though a much smaller percentage than in GB.

The extent that plant need to be kept warm for long periods of time may be minimised through good sharing of reserve, but due to the relative size of the markets this is likely to be of limited benefit to GB.

The reserve requirements and how they are met will vary with our scenarios. With less wind (for example in the Lower RES scenario), there would clearly be less of an increase in warming requirements. Given the importance of peaking plant in providing 4 hour reserve, another way of reducing warming requirements would be to build more OCGTs. Thus in the Capacity Payment scenario, warming requirements would be much lower.

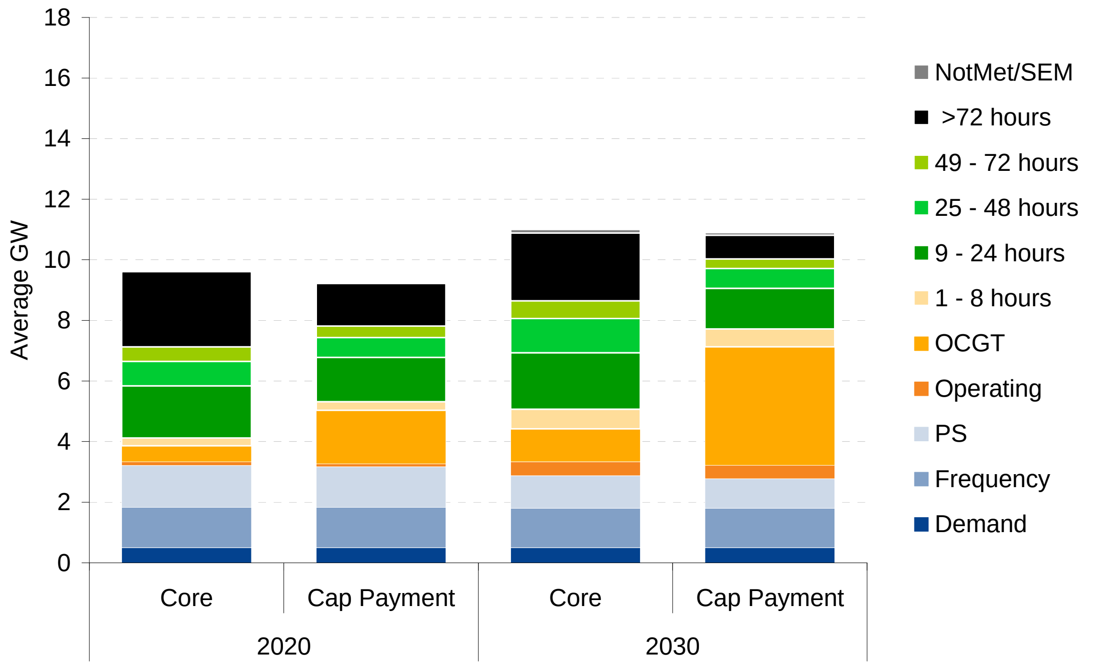
Figure 125 – Level of reserve provision by type / off time (figures include low frequency response), January business day, Periods 18-19



Note: Frequency is the part of low frequency response due to the system frequency falling (for example to 49.5Hz in GB). The NotMet/SEM or NotMet/GB category includes the part of the reserve which is not met, or can only be met through sharing of reserve with SEM/GB as appropriate.

Depending on the type of plant that is built, the reserve requirements and how they are met will vary. With less wind (for example in the Lower RES scenario), there would clearly be less of an increase in warming requirements, as the reserve requirements would be much lower. Given the importance of peaking plant in providing 4 hour reserve, another way of reducing warming requirements would be to build more OCGTs. This is what happens in the Capacity Payment scenario, and is shown in Figure 126. By 2020 and 2030, the amount of capacity that has been off for >72 hours (the black bar) and needs to be kept warm reduces significantly, whilst the provision from OCGTs (in orange) increases substantially. Warming requirements are far lower; in 2030 the average level required which has been off for more than 24 hours is similar to 2010.

Figure 126 – Comparison of 4-hour reserve in GB for Core and Cap Payment scenarios



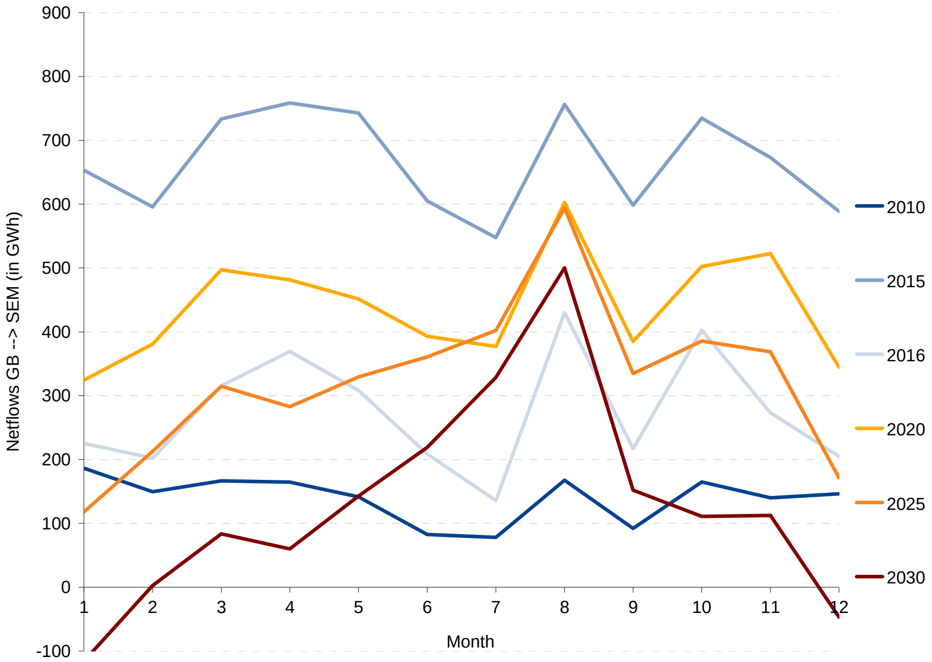
6.6 Interconnection and transmission

6.6.1 How important is interconnection between GB and Ireland?

The interconnection between GB and the SEM becomes of critical importance as the volume of installed wind generation increases. As discussed in Section 2, the larger the geographic area that installed wind capacity is spaced, the more constant and less intermittent the wind generation becomes – thus being heavily interconnected to a much larger market means that it is possible to smooth out the effects of peaks and troughs in wind generation. The SEM is a small market, both in terms of geographic spread and total demand – thus it becomes very susceptible to intermittent generation unless it is interconnected to GB.

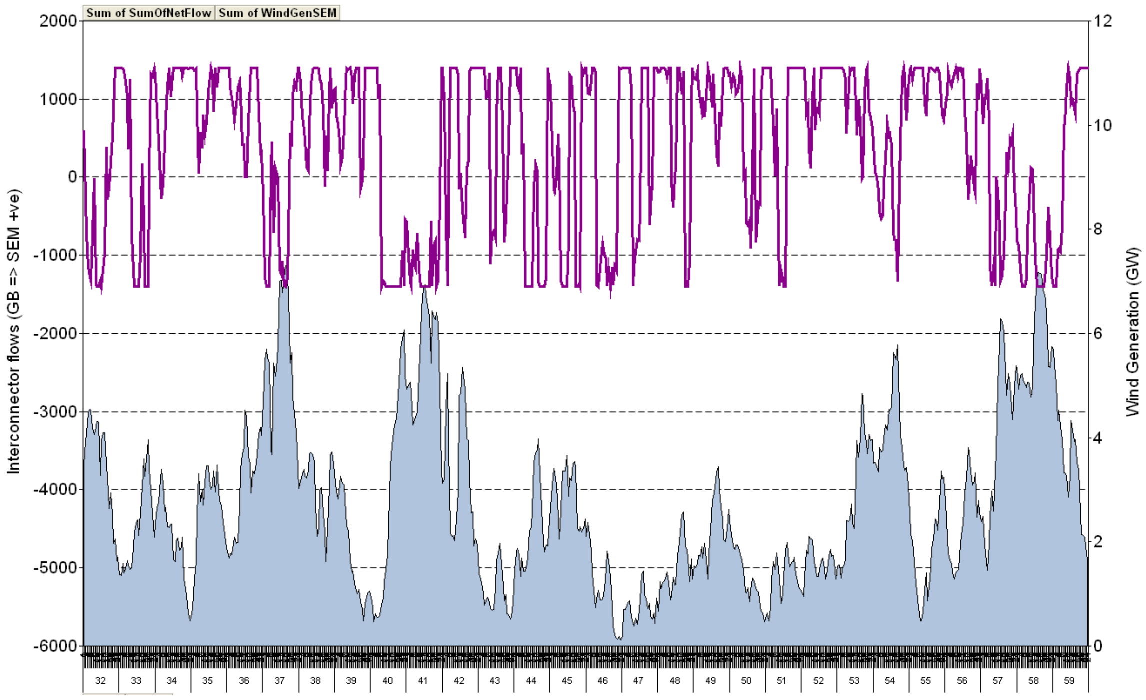
In the Core scenario, a significant reinforcement of existing interconnection is assumed, with the EirGrid East-West interconnector, full reverse flows on the existing Moyle interconnection and a new 500MW link all being built by 2015. Currently, existing flows on the Moyle interconnector are dominated by exports from GB to Northern Ireland. As shown in Figure 127, over time this pattern will change. In 2015, the expansion of the interconnections means that Ireland imports an average of 750MW, with a broadly flat profile across the year. The tightening of the GB market in 2016 means that exports reduce by about half. From 2020 onwards as the volume of wind grows above 6GW, the seasonal profile increasingly shows high imports during the summer, when wind is low, and lower imports in winter. By 2030, January has net exports due to the high wind generation, whilst August has the highest imports as wind reduces.

Figure 127 – Interconnector flows between GB and SEM in Market Schedule



These flows are increasingly driven by wind. Figure 128 shows the interconnector flows compared to wind generation in Ireland for February 2001 wind data in 2030. Although the relationship is complicated by other factors, it is clear that wind generation is a significant driver of interconnector flows, with periods of high generation showing strong exports, and low wind giving high imports.

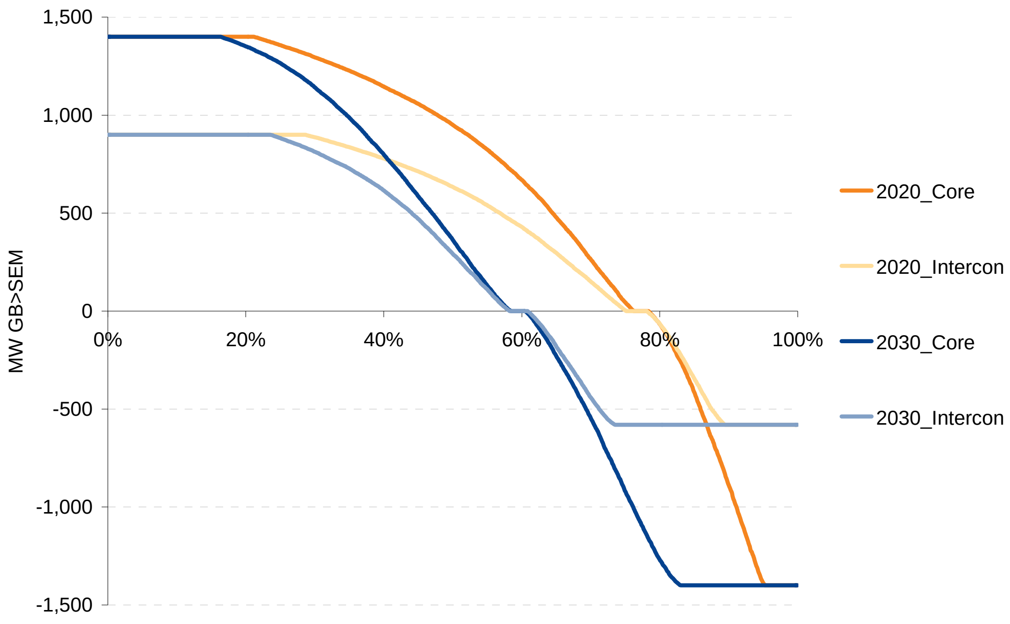
Figure 128 – Interconnector flows between GB and SEM in Feb 2001 in 2030



If less interconnection is built between the two markets, the SEM will be the most affected due to the comparative importance of interconnection to that market. Figure 129 compares interconnector flows in the Core scenario with 1400MW both ways, to the Interconnector scenario, with 900MW import and 600MW export. Unsurprisingly the interconnector is constrained more of the time than before, with exports from the SEM constrained in 10% of the year in 2020 in the lower Interconnection scenario, compared to 5% in the Core scenario, and imports constrained 30% compared to 20% previously.

The smaller interconnection causes a significant increase in the periods and amount of wind de-loaded in the SEM. As shown in the earlier section on wind de-loading (Section 6.4.2), wind de-loading in the SEM increases from 23GWh in 2020 in the Core to 143GWh in the lower Interconnection scenario. By 2030, 1242GWh of wind de-loading in the Core increases to 1945GWh in the lower Interconnection scenario. These results are based on the Market Schedule runs – using the SO Dispatch run (for which data was not available), the wind de-loading would be much greater. In effect, increased interconnection for the SEM allows it to export ‘excess wind’ to the GB market.

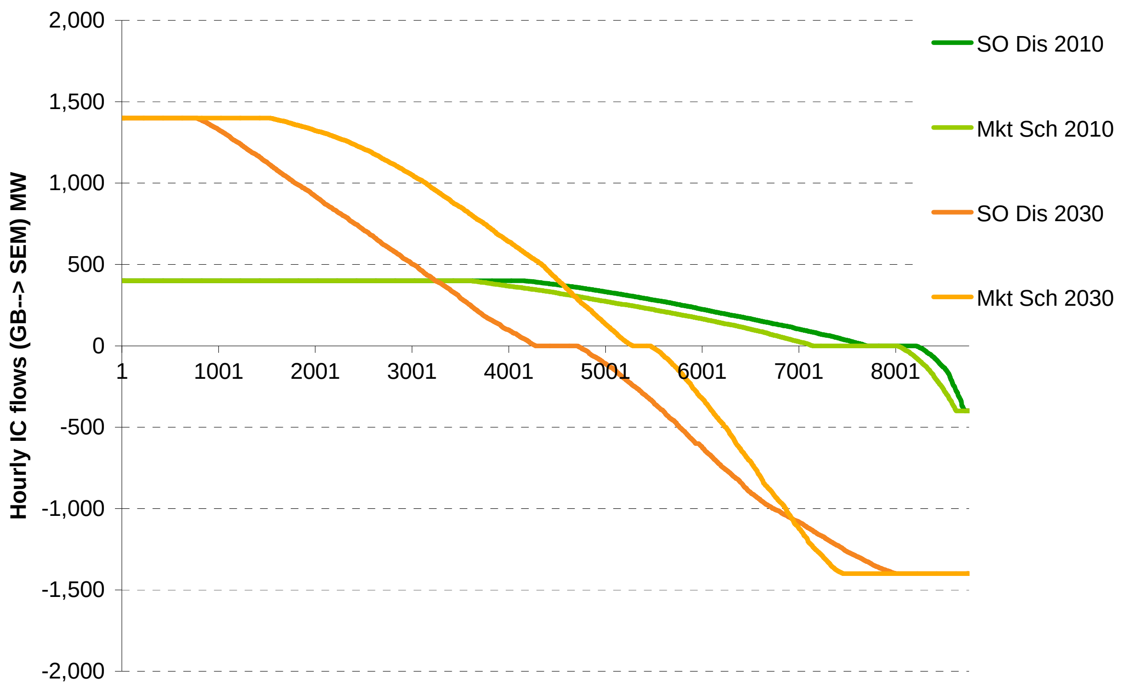
Figure 129 – Duration curve of IC flows in Market Schedule



6.6.2 *How are interconnector flows changed by transmission and reserve and response?*

The interconnector flows shown above are what the Market Dispatch would produce between the GB market and the SEM. In reality, flows may be different due to internal transmission constraints and reserve and response constraints, which are covered by the SO Dispatch run. Figure 130 shows the flows the GB to/from SEM in the SO Dispatch run. Initially the flows are mainly from GB, but flows become more even over time. By 2030, the interconnector is flowing at maximum about 21% of time. In all years, the majority of the time it is not constrained.

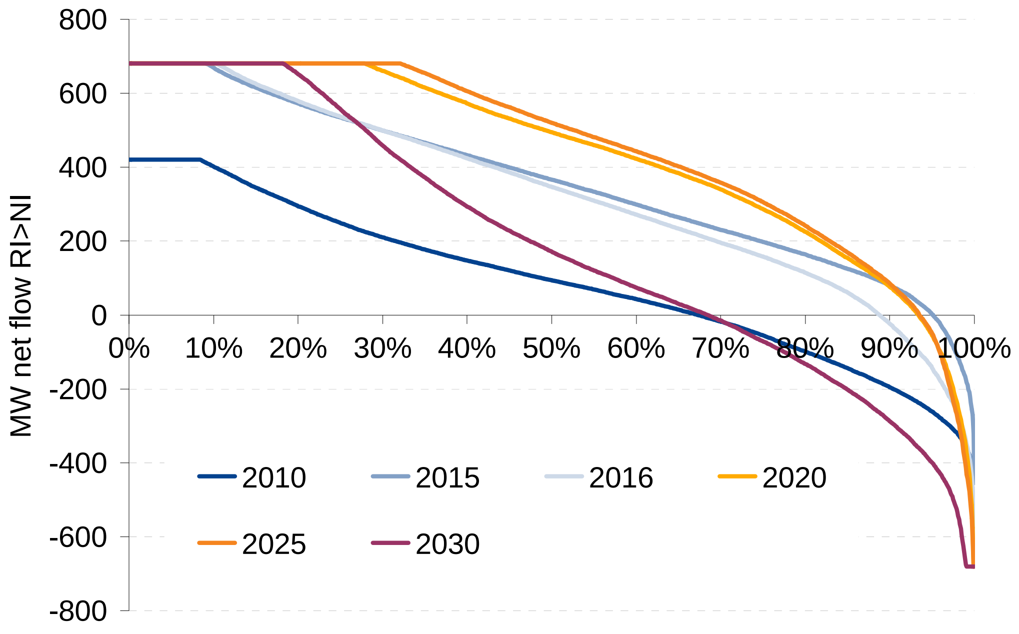
Figure 130 – GB to SEM flows in 2010 and 2030 comparing Market Schedule and SO Dispatch



6.6.3 How might flows evolve between ROI and NI and E&W and Scotland?

Figure 131 shows the net flows from Republic of Ireland (RI) to Northern Ireland (NI). It shows that the flows are from RI to NI the vast majority of the time, particularly from 2015-25 inclusive. This is largely due to the much higher wind penetration assumed (and currently in) for RI compared to NI. In 2010 all the interconnection with GB is in Northern Ireland, whereas by 2015 it is disproportionately in RI. By 2030 a CCS coal plant has been commissioned in NI, which makes the flows a little more balanced. The other observation is that the north-south interconnection is constrained much of the time, peaking at about one third of the time in 2025. While we have disproportionately built thermal capacity in NI, building a still higher proportion of the thermal new entry in Northern Ireland may help slightly, but probably not that much – the interconnection would still be constrained much of the time. With the wind deployment and capacity assumed for the Core scenario, further reinforcement of the north-south interconnection in Ireland is suggested from the results.

Figure 131 – Net Flows from RI>NI (Duration Curve) in SO Dispatch run



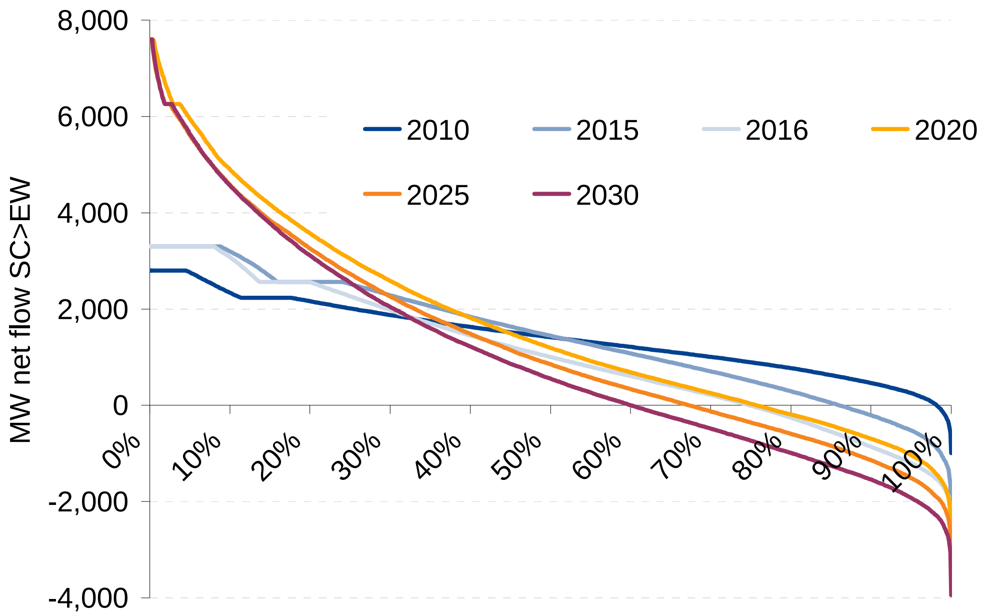
An interesting output related to the NI<>RI constraint is the proportion of periods the direction of the flows on Moyle and East-West differ. One interpretation of this is that power is flowing in circles – the RI-NI interconnection is constrained and so power flows from the Republic to Northern Ireland via England and Wales and Scotland. These numbers are shown in Figure 132.

Figure 132 – Proportion of time flows on Moyle and East-West are in opposite directions

	% of Time
2015	2.5%
2016	4.6%
2020	6.4%
2025	7.3%
2030	2.8%

Figure 133 shows the flow duration curve between England and Scotland. Up to 2016 the interconnection is constrained a significant proportion of the time. From 2020 onwards, the scenario assumes significant reinforcement of this interconnection up to 7.6GW in winter. With this much higher interconnection, the constraint occasionally binds in summer, but rarely in winter[45]. We have assumed all thermal new entry is in England and Wales. If some was in Scotland the constraint would bind more often[46].

Figure 133 – Net Flows from SC>EW (Duration Curve) in SO Dispatch run



6.6.4 *What are the flows within GB for National Grid transmission boundaries?*

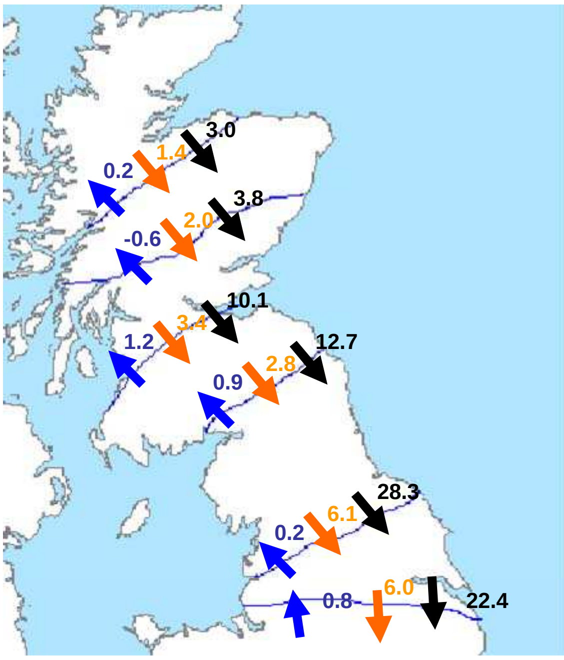
While the only transmission constraint modelled in GB was the England/Scotland border, we have also looked at what the flows would be across 6 transmission zone boundaries. For new generic capacity, we have assumed that within modelled zone (e.g., EW, SC), the new capacity is allocated between zones in proportion to demand. This does seem broadly consistent with the distribution of the nominated sites for new nuclear power stations, but if new power stations were built disproportionately in one zone, there would obviously be an affect on flows. It has also been necessary to assume which National Grid zone our offshore wind sites connect to – this has been based on a number of sources.

45 Our transfer capacities are based on seasonal temperature ratings and outages. They amount to the full value in the winter, and the weighted average of the full summer value and summer value when maintenance is being carried out. Outages are likely to mean that we are underestimating the proportion of time the constraint binds.

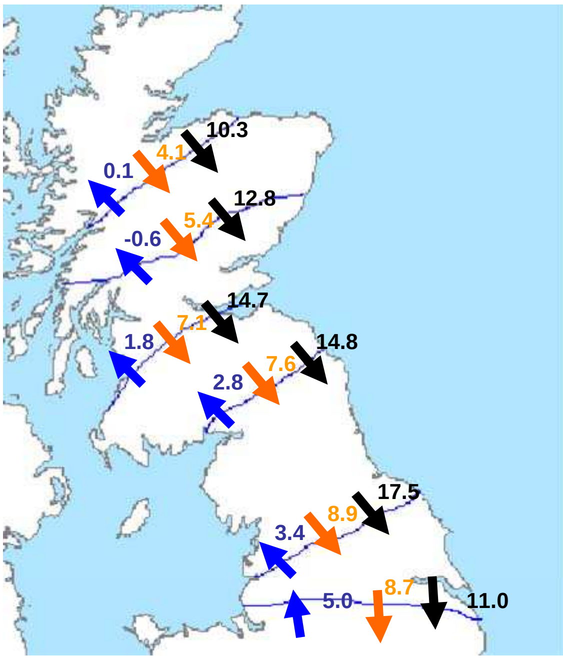
46 It should be noted that none of the nominated sites for new nuclear power stations are in Scotland, http://news.bbc.co.uk/1/hi/sci/tech/7999471.stm#map

Figure 134 – Flows across National Grid boundaries

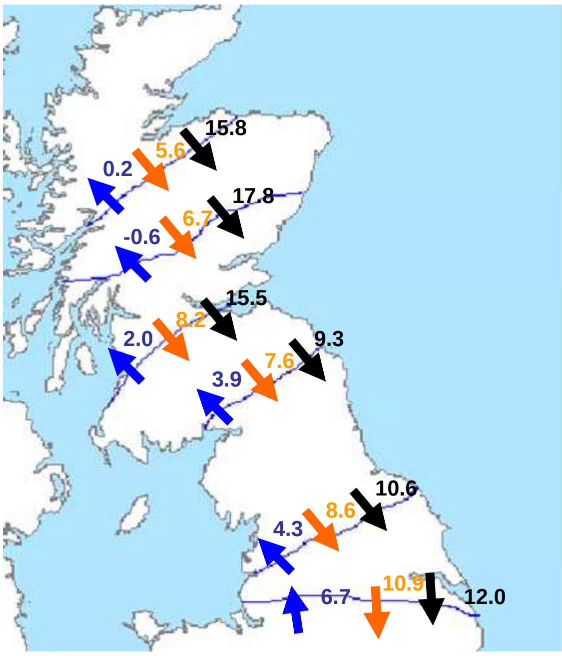
Flows in 2010



Flows in 2020



Flows in 2030



KEY

Annual TWh (Net)

Max GW Southbound

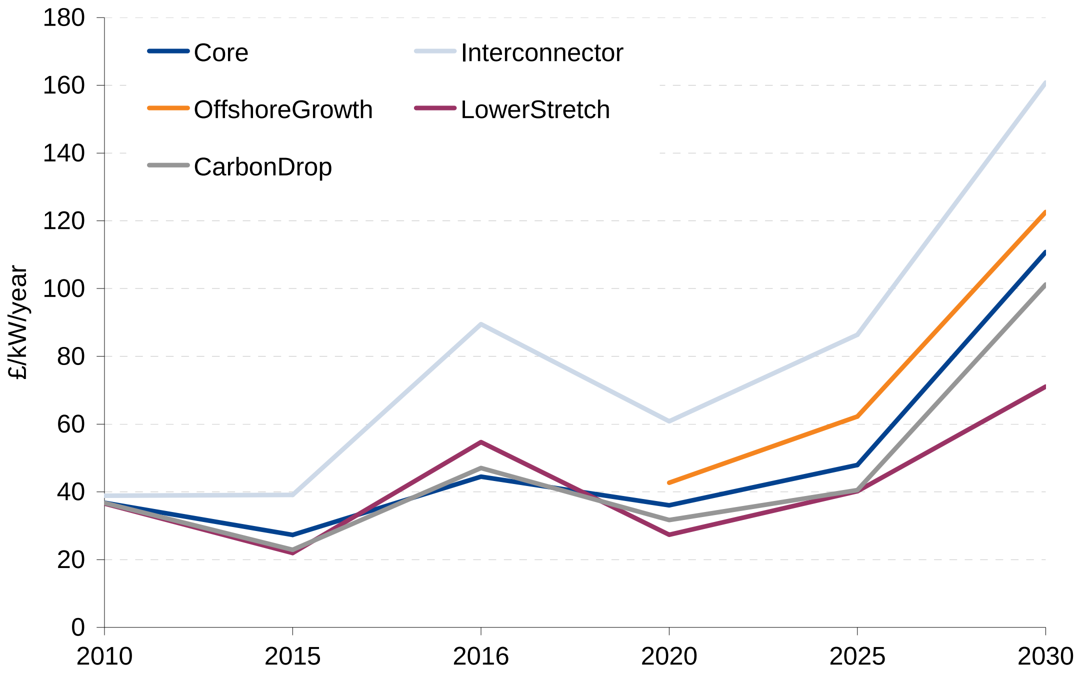
Max GW Northbound

As the volume of installed wind increases the volume of peak north and south flows increases. Annual flows also increase, quite significantly, particularly in the most northern zones.

6.6.5 What is the value of the interconnection between GB and the SEM?

The significant interconnection reinforcement between GB and SEM, and the fact that the flows are rarely constrained, give rise to the question about the value of the interconnection. Figure 135 shows annual interconnector revenues for a number of the scenarios. Assuming a capital cost of £1120/kW[47], annual returns required to make a reasonable return would be £100-£150/kW, depending on the required IRR. The annualised revenues are well below this threshold in all the scenarios until 2030. This suggests that the level of interconnection built between GB and the SEM may be greater than required in our scenarios.

Figure 135 – Annual interconnector (GB/SEM) revenues per year by scenario



Note that this study should not however be treated as a detailed assessment of any future interconnector build programme. We have not considered, or only partially considered:

- the effect of different fuel prices;
- the effect of within year fuel price volatility, including in the difference in GB and SEM gas prices;
- revenues from other sources (e.g. reserve and response) – as the flows were significantly different in the Market Schedule and System Operator Dispatch runs this may be an issue; and
- the effect of a wide range of different plant new build, and demand growth.

47 http://www.wepr.co.uk/EirGrid-awards-contract-for-construction-of-the-East-West-Interconnector.asp

We have also not used parameters (e.g. losses) specific to any particular project (the losses used are based on Moyle).

However, the results can be used to compare our scenarios. As Figure 135 shows, the interconnector scenario has the highest annual revenues – this is to be expected, since having less interconnection leads to less convergence of prices. The other scenario with higher revenues than the core throughout is the Offshore Growth scenario. There are two reasons for this:

- the concentrated wind increases volatility in GB prices; and
- much of the wind is off the East Coast of England (in the case of Dogger Bank well off the east coast) – this is likely to result in lower correlation with Irish wind.

The scenarios which are lower than the core scenario are the Lower RES (apart from 2016, where the margin in GB is tighter in the Lower RES) and the Carbon Drop. In the Lower RES, with less wind, prices are less volatile. In the Carbon Drop, wholesale prices are lower on average. As would be expected, both these effects lead to lower revenues.

The main drivers of interconnector revenues (applying across all scenarios) are tight system margins in GB (2016 and 2030), and price volatility (which increases as more wind is commissioned).

6.6.6 How important is interconnection between GB and the Continent?

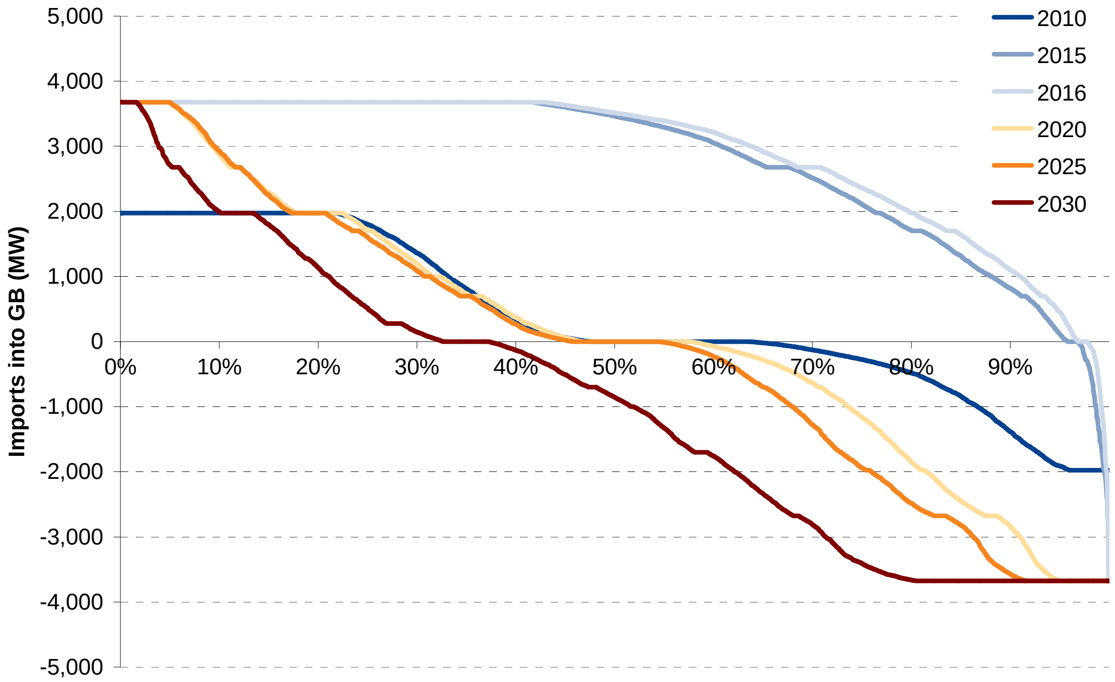
The modelling undertaken for this study examines flows between GB and the Continent – however, these markets are not modelled fully like the GB-Ireland interconnection. Instead, flows are modelled using static border prices, with an hourly price profile, to simulate Continental prices in the Netherlands, France and Belgium. These prices have been calculated using a mixed-integer linear programming model similar (though less sophisticated) to Zephyr that covers the Netherlands, Germany, Belgium and France, using the same fuel price assumptions as the Zephyr scenario. Thus this modelling does not take account of how GB interconnection may affect these markets, not the extent to which wind generation will be altering prices on the Continent.

Given this caveat, there are still some relevant findings from analysis of the flows, and the extent to which interconnection between GB and the Continent is being driven by wind.

Currently there is a single interconnection linking GB and the Continent – this is the 2GW IFA (Interconnexion France-Angleterre). In our modelling, we assume that both BritNed (GB to Netherlands) is commissioned in 2012 at 1000MW and a connection linking GB and Belgium comes on line by 2015 (700MW). Thus by 2015, GB is connected to the Continent with 3.7GW of capacity. As the installed capacity of wind increases in GB, these interconnections become more important in balancing the GB (and to a lesser extent the SEM) system.

Figure 136 shows a duration curve of Continental imports and exports from GB. In 2010, there is more import than export, due to lower priced French nuclear generation. In 2015 and 2016, given the tightness in the GB market, GB imports heavily with very few periods of exports. However, by 2020 this has switch to a more balanced position with roughly the same amount of exports and imports. By 2030, with very significant installed wind capacity, GB becomes a net exporter of power.

Figure 136 – Imports into GB from the Continent – Core scenario

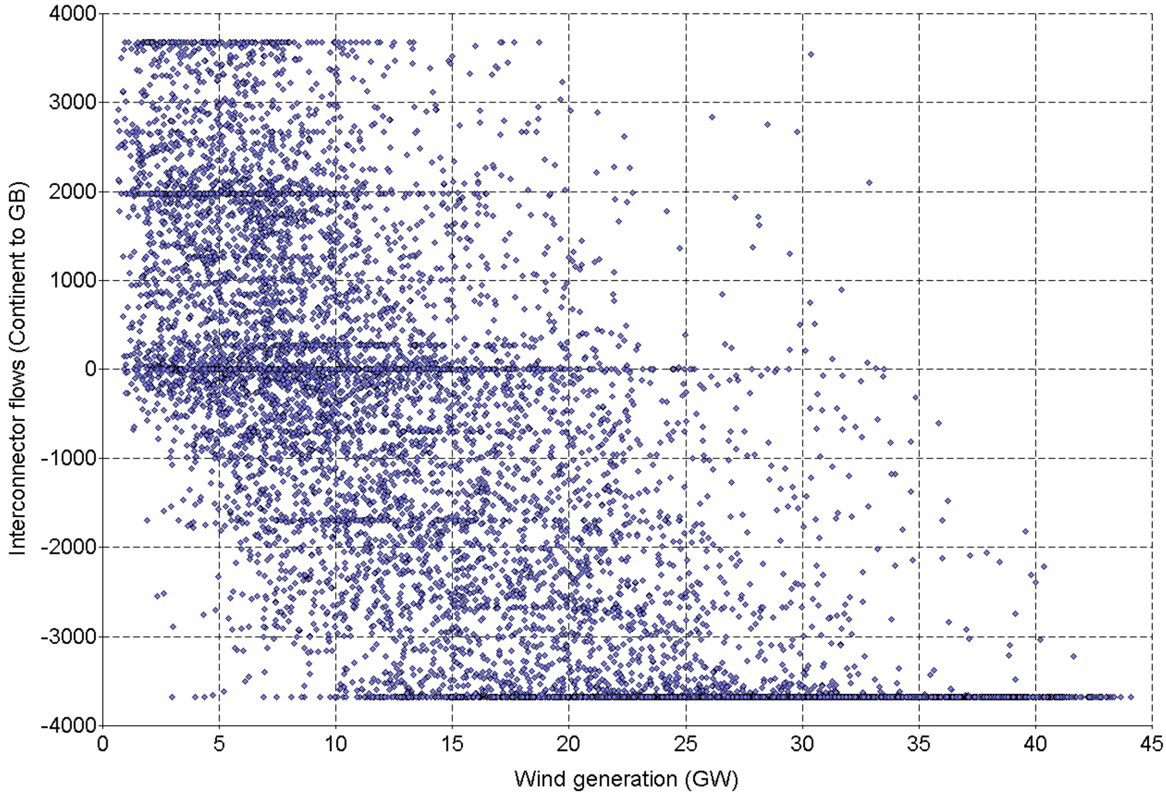


Results taken from the Market Schedule run

Figure 137 shows a scatter chart comparing wind generation in each hour with interconnector flows between the Continent and GB (positive flows are from the Continent to GB). There is a relationship that is similar to that shown between GB and the SEM, with high volumes of wind frequently associated with exports of generation to Continental Europe, and low wind associated with imports.

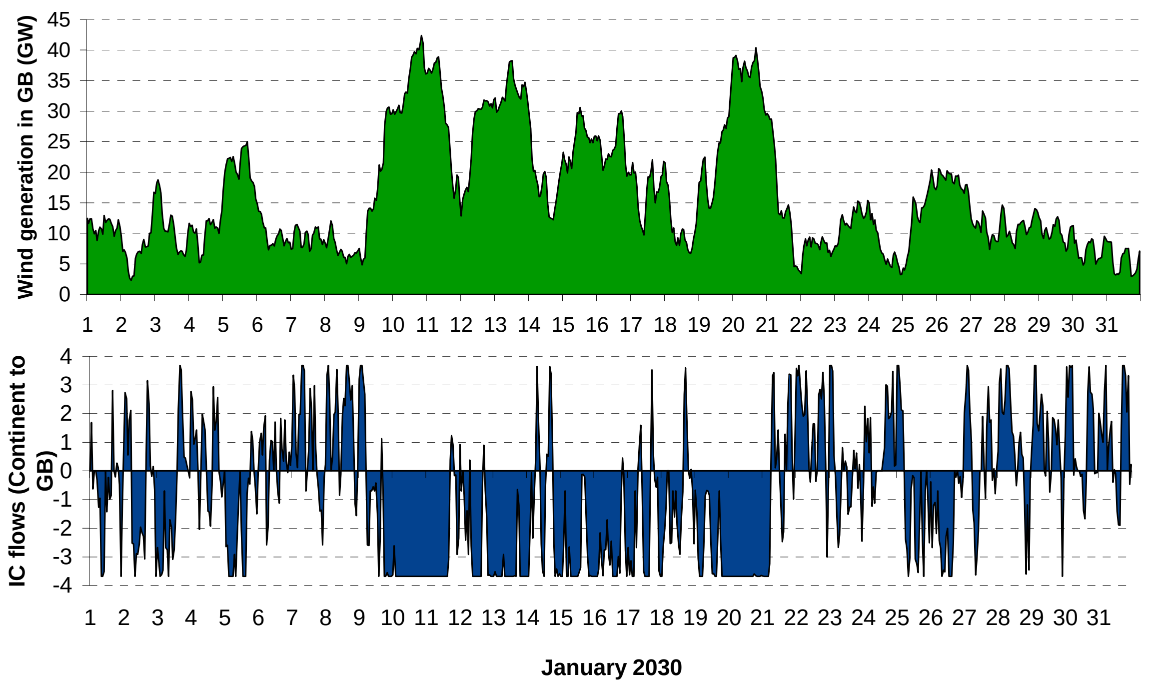
The 'zoom in' on a single month shown in Figure 138 illustrates how the interconnection changes depending on wind. Between 10 January and 20 January, a period of high wind speeds drives exports from GB to the Continent. From 20 January, wind generation reduces, leading to more imports and a more balanced position with the interconnection alternating between import and export.

Figure 137 – Wind generation compared to GB Continent interconnection (2030)



Data for Core scenario in 2030, using Monte Carlo year 2006.

Figure 138 – Continent-GB interconnector flows in January 2030



6.7 Market arrangements

The focus for the study has primarily been on commercial rather than regulatory issues. Nevertheless, the results shed light on a number of important points of market design, with others for possible future consideration.

This section of the report draws on an analogy that market design should be like audio equipment, i.e. that it should faithfully reproduce the underlying fundamentals (however discordant). The design needs to suit the market circumstances and should follow the underlying economic principles of applying prices to whatever is 'scarce', whether this is energy, flexibility, reliable capacity, reserve, etc.; such that the provision of 'scarce' services should be rewarded through transparent market prices available to all providers of the same service. To the extent that market prices for the provision of services deviate from this principle, long term investment and/or short term dispatch are liable to be suboptimal.

Some market design questions relate to differences between GB and the SEM, while others relate to design aspects which are (potentially) missing from both markets:

- Do capacity payments materially improve outcomes, compared to an energy-only market?
- What are the implications of day-ahead rather than within-day gate closure?
- Are there inefficiencies associated with ‘simple’ as opposed to ‘complex’ bidding (i.e. all-inclusive per-MWh prices rather than separate pricing for starts and no load costs)
- Should market pricing capture system operation requirements?
- Are there distortions arising from priority dispatch or the form of subsidy for renewables?
- Are existing market arrangements adequate to deal with large volumes of renewable generation?

6.7.1 *Do capacity payments materially improve outcomes, compared to an energy-only market?*

Would a capacity payment mechanism be more expensive?

Table 29 compares the end-user costs of the current BETTA mechanism in the Core scenario with the Capacity Payment scenario. End-user costs represent the cost of buying electricity in the wholesale market plus the cost of subsidies paid to renewables, excluding transmission costs.[48] Both scenarios assume the same demand, and growth in renewables, CCS coal and nuclear generation – thus the costs from subsidies is identical in both scenarios. More importantly, the Core scenario includes the assumption that security of supply is maintained, requiring 1GW of OCGT build by 2030 which under present assumptions is commercially uneconomic. A capacity payment is one potential way of making this build economic.

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48 This is the hourly market price multiplied by the demand in that hour for all periods in the year plus the cost of ROCs in a year.

The two scenarios give very different profiles of prices – both hourly and at an annual average. The Core scenario leads to much more volatile prices, with peak prices greater than £1000/MWh. Prices also rise significantly in response to system tightness – in particular in 2016 and 2030 when new capacity is required. As a result, end-user costs tend to be more volatile with some periods of much lower costs, but also periods of much higher costs. Recalling the assumption that security of supply is maintained in the Core scenario (relying on some uneconomic OCGT build), the Capacity Payment scenario generates much flatter prices – both day-by-day and year-by-year, leading to a much more stable – though higher (given the assumed higher level of investment) – overall costs.

By discounting the end-user costs back to 2015 at 8%, it is possible to compare the two scenarios. Between the two scenarios there is a marginal difference in cost, with the Core scenario costing £228bn whilst the Capacity Payment scenario is £231bn over the period. The increase is principally due to the higher generation investment in the Capacity Payment scenario. Thus from 2015 to 2030, the choice of market mechanism does not make a significant difference to end-user costs. (The indivisibility of investment to some extent clouds the picture since there is additional OCGT build by 2030 in the Capacity Payment scenario but no less CCGT build. In a scenario with higher demand growth there may be more opportunity for substitution of OCGT for CCGT build leading to lower overall costs.)

Table 29 – Relative costs

2008 £'bn	Core scenario (BETTA continues)	Capacity Payment
2015	23	26
2016	28	26
2020	25	27
2025	25	26
2030	27	26
Discounted to 2015 @ 8%	**228**	**231**

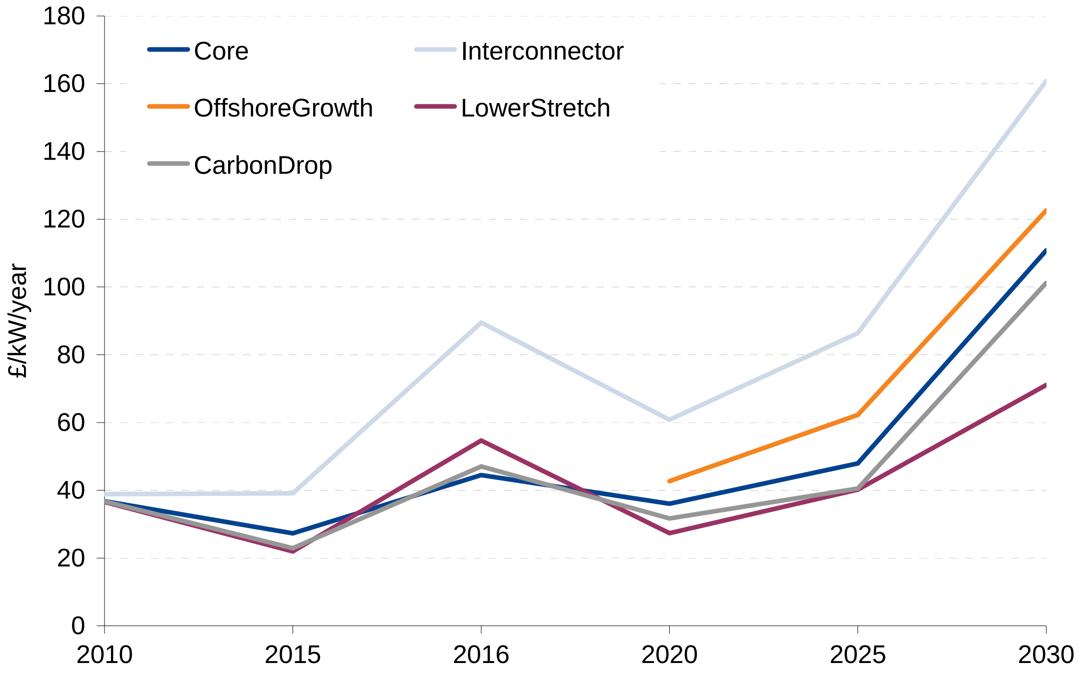
6.7.1 What are the implications of day-ahead rather than within-day gate closure?

An important difference between BETTA and SEM is the timing of gate closure, the last time at which participants can take pricing decisions. This has its greatest impact on interconnector scheduling, since firm prices are fixed at 10:00 day-ahead for the following day to 06:00 (20-44 hours ahead). This restricts the ability of the interconnector to accommodate wind output, which is rather uncertain over these timescales.

It would be possible to conduct model runs which explicitly perturb interconnector bidding in order to test inefficiency of these ‘seams’ issues, but this has not been done to date.

A measure of the impact of day-ahead gate closure may be inferred from the revenue of the interconnector when scheduled efficiently; and by inference the potential system cost of inefficient pricing of interconnector flows. Figure 139 (a replica of Figure 133 above) indicates – with many caveats – the annual interconnector revenue for a number of the scenarios. With 1400MW of interconnection, a figure of £40/kW/year (a value relevant for the period to 2025) implies revenue to the interconnector owner of around £56 million annually, (with further unquantified benefits in terms of consumer surplus and producer surplus). If (arbitrarily) 10% of this value is lost through early gate closure for interconnector prices, the system cost might be estimated to be around £5 million annually. By 2030, the potential inefficiency increases sharply, albeit with a marked contrast between the lower RES scenario (~£70/kW/year / £10 million annual system cost) and the Severn Barrage scenario (~£160/kW/year / £20 million annual system cost).

Figure 139 – Annual interconnector (GB/SEM) revenues per year by scenario



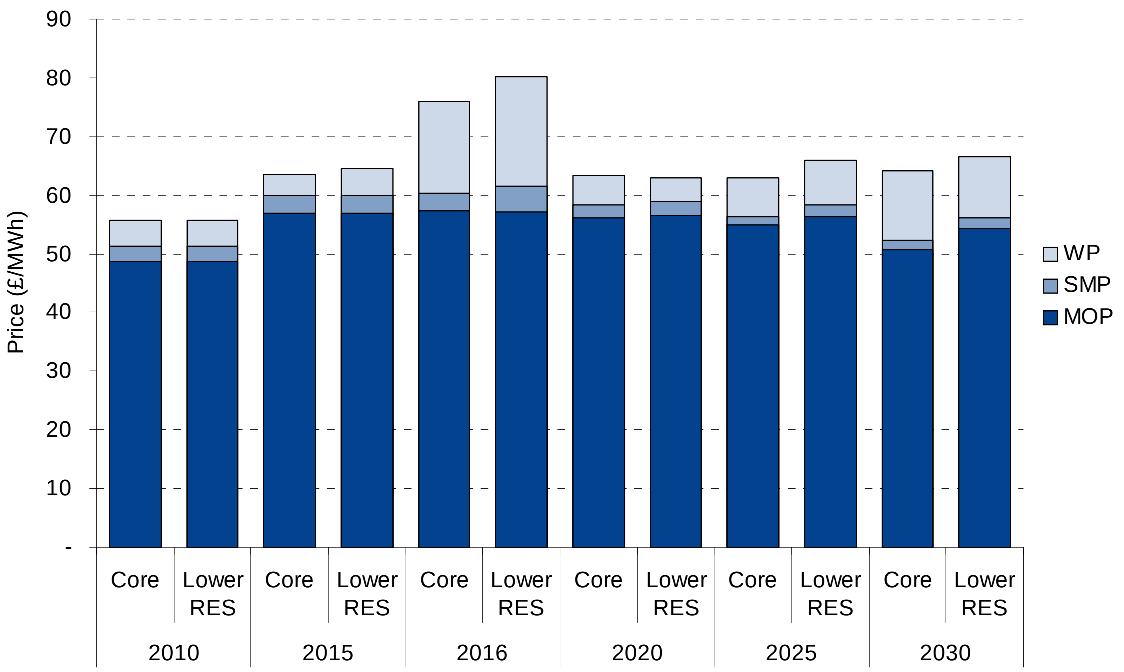
The inference is that as wind penetration increases, the value of interconnection and the potential efficiency loss associated with day-ahead pricing for interconnector trades increases markedly. However the absolute sums involved are relatively small, implying that day-ahead gate closure for interconnector trades is not a major impediment to system efficiency.

6.7.2 *Are there inefficiencies associated with 'simple' as opposed to 'complex' bidding (i.e. whether to price per MWh or to apply prices for starts, no load, etc.)?*

The BETTA market requires generators to price the risk of starts and part-loading into simple per-MWh prices and their own self-dispatch decisions, whereas SEM permits generators to bid separate incremental, start and no-load costs with market optimisation of these costs. In principle the SEM approach reduces risks (and commercial freedom) for generators with the potential of improving the system-wide optimisation of start and no-load costs. The relative contribution of start and no load to prices and to costs gives an indication of the potential significance of the simple bidding rules

The model calculates wholesale prices as three components, a 'merit order price' (MOP) which excludes start costs and includes no-load costs assuming units are operating at full load, 'SMP' which includes a further element covering the cost of unit starts and part-loading, and the wholesale price (WP) which includes the value of capacity. Figure 140 reveals this breakdown for GB for the Core and Lower RES cases. It illustrates that the contribution of start and part-loading costs to wholesale price is small in the Core Scenario (from 5% of wholesale price, falling to 2% in the later period), with a slightly higher value (5-6% falling to 3%) in the Lower RES case. The equivalent figures in SEM are marginally higher (with start and part-loading costs contributing 4-6% of the wholesale price).

Figure 140 – Breakdown of market price into components



As another indication of the influence of simple or complex bidding, the share of generation cost in GB may be broken down to reveal the start costs. Table 30 shows the start cost as a % of total generation cost in GB from the Market Schedule run.

Table 30 – Start costs as% of total generation costs

	GB	SEM
2010	1.1%	1.4%
2015	1.2%	2.1%
2016	1.0%	2.5%
2020	1.5%	2.7%
2025	1.9%	3.0%
2030	2.2%	3.4%

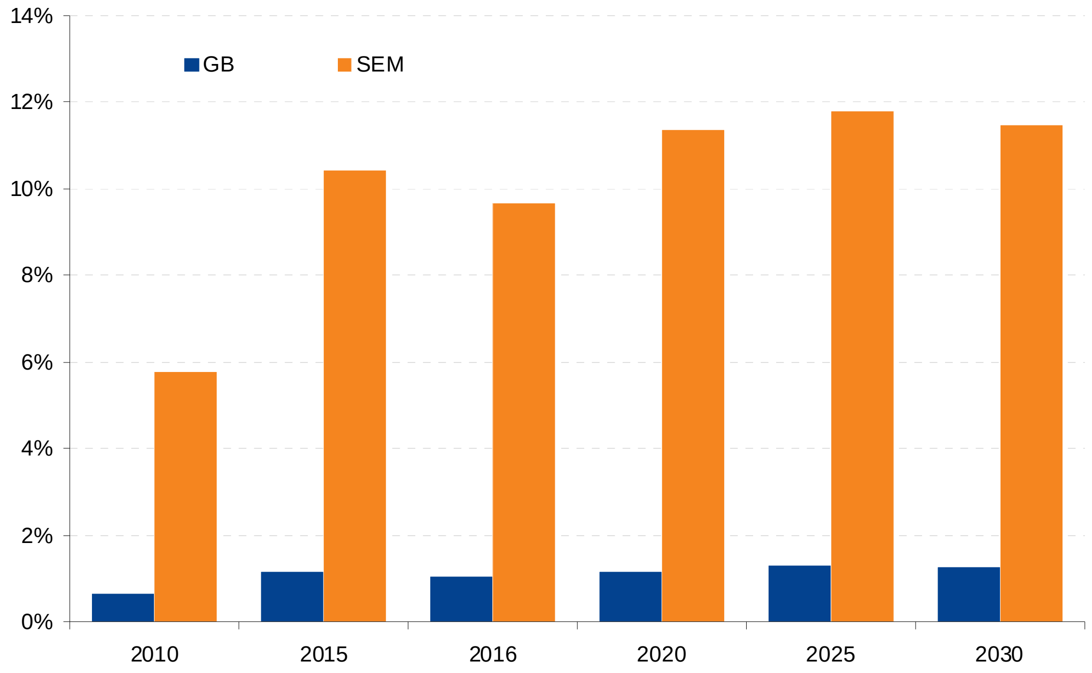
The inference is that part-loading and start costs have a limited influence on dispatch costs or market pricing, and that the impact of choosing either simple or complex bidding on dispatch efficiency is likely to be rather small, perhaps falling rather than rising in the later years.

6.7.3 Should market pricing capture system operation requirements?

The market pricing in both BETTA and SEM excludes direct consideration of reserve, response or transmission constraints and other aspects of 'flexibility' such as the costs of maintaining thermal units in hot standby. These services are priced separately, outside core market scheduling and pricing processes, with varying degrees of market transparency.

As an indicator of the potential for market distortion if these services are not correctly prices, Figure 141 shows, for the Core Scenario, a measure of re-dispatch between the Market Schedule and the SO Dispatch case. This is calculated by summing half[49] of the absolute MW re-dispatch for each generation technology in each hour, and dividing the resultant MW total by annual demand.

Figure 141 – Extent of re-dispatch between SO Dispatch and Market Schedule



49 The SO Dispatch case includes reserve, response and North-South constraints in both GB and SEM. Re-dispatch to meet these constraints on system operation will raise the output of some units and lower the output of other units compared with the Market Schedule results, therefore the absolute MW changes are halved in generating the results. The metric does not capture re-dispatch of wind generation or within a technology type, for example if a CCGT is de-loaded to bring on another part-loaded CCGT for response provision.

The metric reveals that re-dispatch for reserve, response and the limited transmission constraints modelled is material in SEM (over 10% of total generation) but far lower in GB (around 1%). The inference is that in GB these issues can more safely be excluded from the core market processes, whereas in SEM there is a far stronger case for the market prices to include these services in some transparent fashion.

6.7.4 Are there distortions arising from priority dispatch or the form of subsidy for renewables?

The renewable support schemes in the Republic of Ireland and Northern Ireland are fundamentally different. In Ireland, wind plants have been assumed to bid with a price of zero. In Northern Ireland, have been assumed to bid at the negative of the ROC price. The future treatment of priority dispatch and wind in the SEM is under regulatory review at present, so these assumptions are designed to test the implications of different bidding behaviour rather than the present reality.

A simple measure is the frequency with which wind generation is de-loaded in the Republic of Ireland and in Northern Ireland. Using the Core scenario, in the Market Schedule (which excludes reserve and response as well as north-south transmission constraints), the number of periods in which some wind is de-loaded is very much higher in the Republic of Ireland than Northern Ireland. The difference is more marked in the SO Dispatch case, with over 2TWh of wind de-loaded by 2030 (9.3% of the unconstrained wind output compared with 4.1% in Northern Ireland).

Table 31 – Comparison of de-loaded wind in NI and ROI – Core scenario

	SO Dispatch				Market Schedule	
	GWh deloaded		Periods		Periods	
	NI	ROI	NI	ROI	NI	ROI
2010	0.0	2.4	0	152		
2015	-	34.4		983		
2016	-	34.0		979		
2020	-	287.0		2,853	-	72
2025	0.1	816.1	1	3,515	1	302
2030	47.5	2,081.8	1,301	4,062	29	858

This result implies that if wind generation bids in different ways in the two jurisdictions then there is the potential to transfer significant volumes of renewable generation output between Ireland and the UK.

6.7.5 Are existing market arrangements adequate to deal with large volumes of renewable generation?

This is the most fundamental regulatory question of all. The key issue is whether the market will adequately reward the delivery of 'scarce' services in future in support of investment.

The analysis to date indicates that the key services in future will include the provision of reliable capacity and (especially in SEM) the re-dispatch of plant to meet reserve and response constraints. Our assumptions on there being sufficient generation investment to maintain security of supply are set out above in Section 4.2.1. Given this basis, even at very high levels of renewable penetration, we have not found a 'tipping point' at which market prices collapse or investment in conventional generation cannot continue.

We have identified that the existing relationship between system scarcity and the capacity component of market price will need to change in future in the absence of a formal capacity payment mechanism in GB. A key conclusion is that in order for security of supply to be maintained at current levels without significant involvement by the demand side, there would need to be a material increase in the capacity value accrued by peaking and low-merit generators, compared with that in evidence in today's market.

In SEM, the need for flexible generation is well served by the existence of a capacity payment mechanism. However, the extent of re-dispatch for reserve and frequency response compared with the market schedule suggests that some form of market pricing for the delivery of 'flexibility' is desirable to ensure that these services are adequately rewarded.

6.8 System security

6.8.1 Will the system be less secure than at present?

For the purposes of this study, we have assumed that sufficient generation will be built to ensure that a maximum of two periods of supply loss will be experienced on average across the 8 Monte Carlo simulations. This has been informed by the standard for the SEM of 8 hours LOLE (Loss of Load Expectation) which we have reduced to two hours to take into account that we are not modelling transmission constraints on a line-by-line basis. We believe that two hours gives a reasonable view as to the tightest that a system might be permitted to get to, either before the System Operator intervenes (as in the SEM), or the market or government intervened in GB. In reality, with transmission constraints, the loss of load would be a greater number of periods than this.

As a result of this assumption, the simple answer to the question posed above is that in our results, the system will remain as secure as present since that is an input to our modelling. Nevertheless, the study reveals more in the nature of the security margin and the stresses which will affect it in present, particularly the economics of provision of low-merit generation capacity.

To ensure that a maximum of two hours LOLE is met, in order to maintain sufficient generation capacity, we assume that at any given level of system margin the value of capacity is significantly higher than at present (although the average levels on a time-weighted average basis are similar), and assumes that plants operating at the relevant times are able to capture the full capacity value for those hours. In GB, absent a capacity mechanism, this still does not permit economic build of OCGT which achieve a very low load factor. This issue merits further consideration.

For this study, we have examined system security using three measures:

- hourly capacity margin;
- expected energy unserved; and
- periods when N-1 contingency is breached.[50]

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[50] The N-1 requirement is that system security must be maintained in the event of the loss of the largest infeed load. We define this being breached if insufficient capacity is available to cover this loss (i.e. system margins drop below the N-1 requirement).

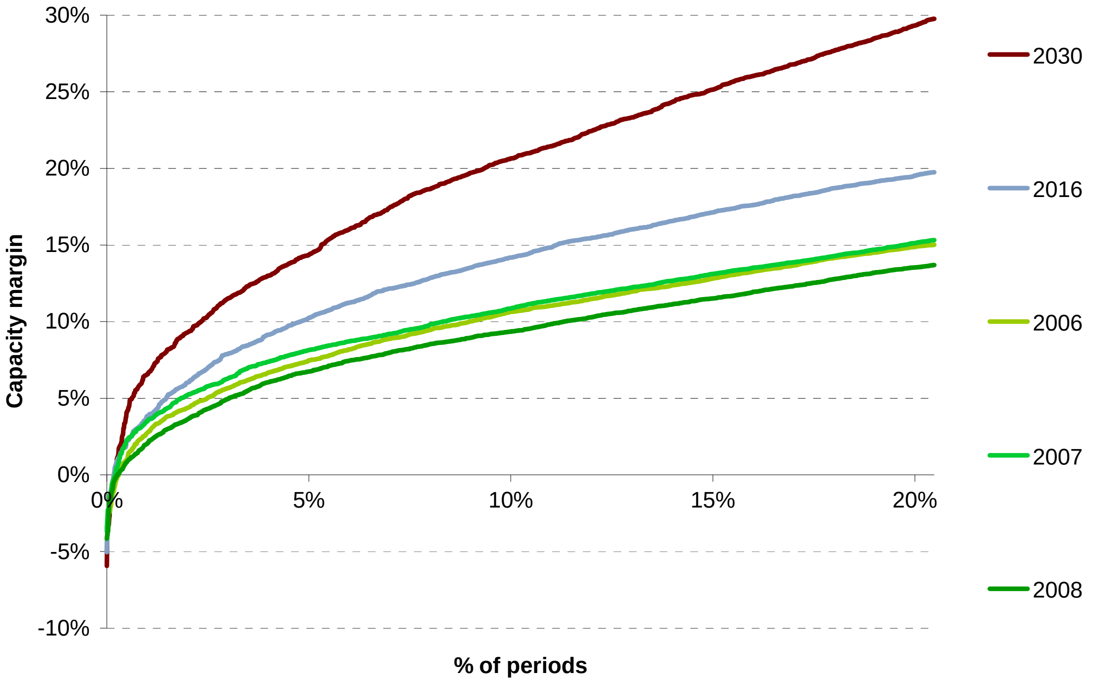
The analysis is based on the Market Schedule run. This is because the England/Scotland transmission constraint rarely binds, and it is most likely to bind when it is windy, when capacity margins are not likely to be tight. In SEM, while the NI<>RI constraint binds more frequently, this is again most likely to be when it is windy. There are a number of caveats with our approach:

- We model demand with hourly resolution, so do not fully model the possibility of demand being higher at some point within the hour.
- There will be times when in Zephyr, demand can be met, but there is not enough capacity left over to cover low frequency response. In mitigation, we base generation availability on actual data, so that outages are taken into account in our availabilities.
- There is an increasing number of periods (particularly in GB) with insufficient spare capacity to meet the reserve requirement. An investigation of the implications of this is beyond the scope of this report, but the effect is not likely to be major.
- In reality the reserve and response requirements do not produce 100% security. If (for example) two EPRs have outages in a short space of time (<<0.5 hours), or the wind forecast error is more than assumed in the reserve requirement, there may be additional unserved energy. However, as these events are likely to be very rare, this is likely to be a fairly small contribution.
- We have not modelled interconnector outages.
- We have not modelled most transmission constraints (noting that is hard to predict where these will be in 20 years time).
- We have assumed there is always sufficient capacity available in continental Europe to cover imports to GB. Examining this issue is beyond the scope of this study.

6.8.2 How will capacity margins change?

Assuming that system security standards are maintained, as we do in the Core scenario, increasing wind penetration will lead to more periods with greater capacity margins. This is shown in Figure 142 for GB for historical years of 2006, 2007 and 2008 (with very little wind generation), along with 2016 and 2030 where there is increasing wind generation. Although the number of very tight periods is similar between historical and future years, the capacity margin on average is much greater in 2016 and even more so in 2030. This reflects the extra generation that is required as backup for the periods where there is little or no wind generation.

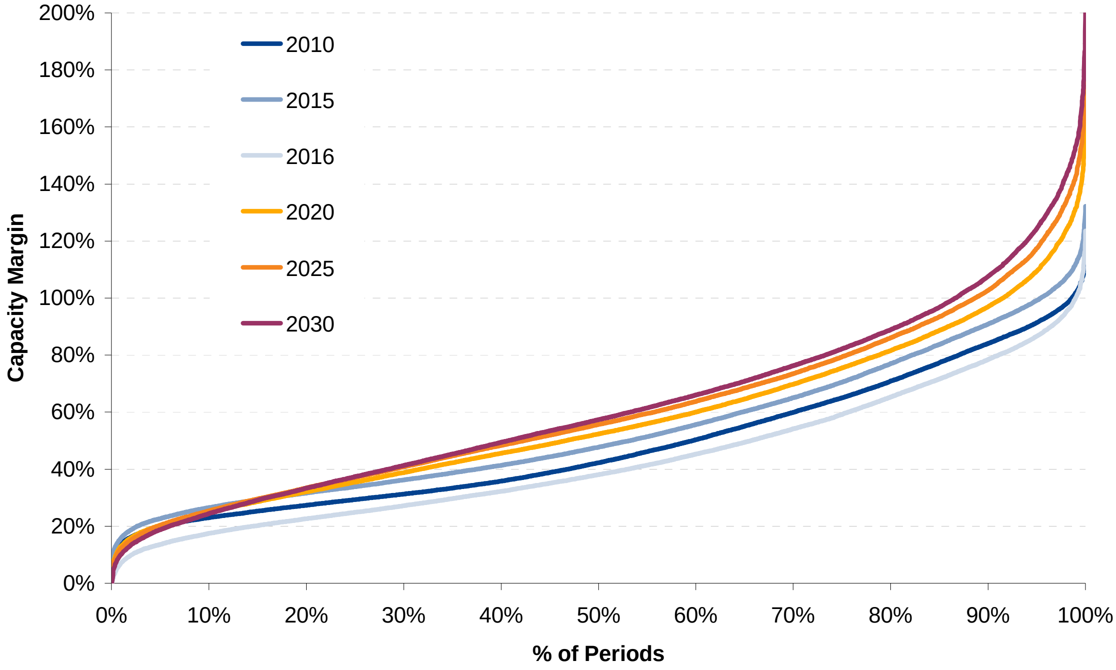
Figure 142 – Capacity margin duration curve for GB (top 50% of periods)



Data for 2016 and 2030 from Monte Carlo 2007

Figure 143 shows the capacity margin duration curve for all years and all Monte Carlo scenarios. The change in the capacity margin duration curve is illustrated by comparing 2015 and 2030. In the 85% of periods with highest margins, there is a larger margin in 2030. The highest margin in 2030 is over 50% higher than the highest margin in 2015. However, in the 10% of periods with the tightest margin, capacity margins are smaller in 2030. Our hourly prices contain a value of capacity when the margin is less than about 30%. In 2016 and 2030 (the two years with the most unserved energy), in 2016, 36% of periods have a capacity margin of less than 30%. This compares to 16% in 2030. For SEM, the duration curve would change even more, with a higher level of wind penetration. However (depending on the effect of the interconnection on Irish plant investment), SEM would be very unlikely to be 1400MW (the assumed interconnection capacity) short of capacity, so is only likely to have a problem at times GB has a problem.

Figure 143 – Capacity margin duration curve (GB)

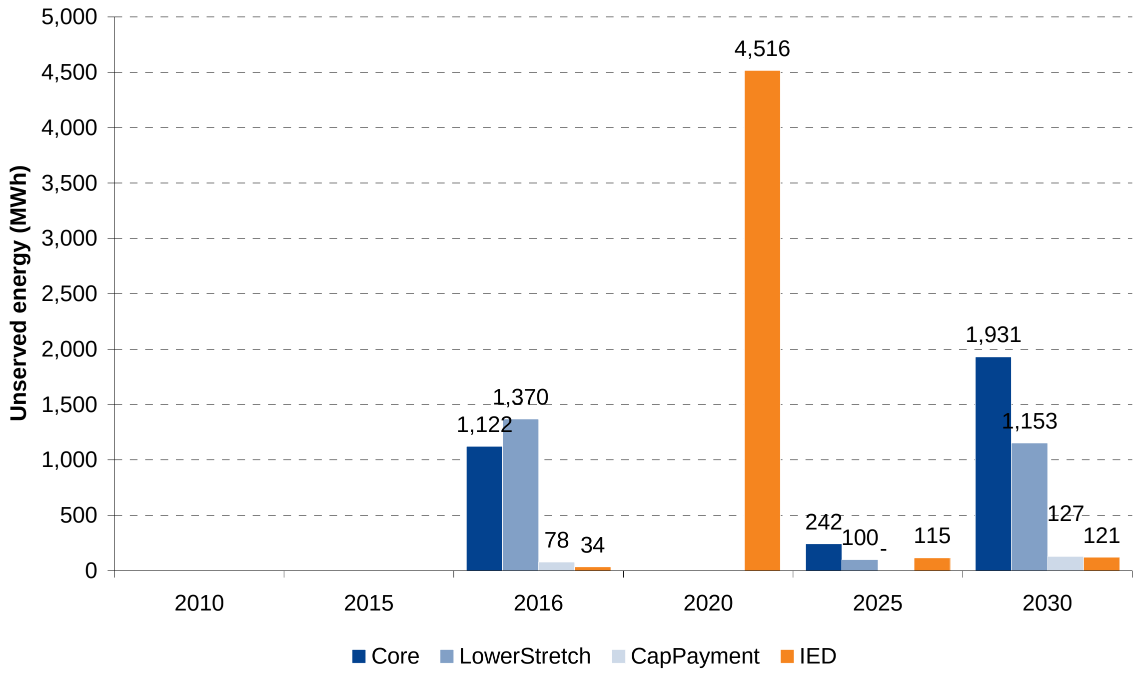


6.8.3 How much unserved energy might there be?

For the reasons outlined, we have no unserved energy demand in SEM. In GB in the Core scenario, the unserved energy (averaged over Monte Carlo scenarios) is 1120MWh in 2016, 240MWh in 2025, 1930MWh in 2030 and zero in other years. We believe these are comparable with historical values. It is interesting to note that in 2016 there are 1.5 periods /year with unserved energy (5 of which are less than 200MWh), whereas in 2030, despite the unserved energy being 70% higher than in 2016, there are 1.75 period/year with unserved energy, a very small increase on 2016 (in 2030 only two periods have a loss of load below 200MWh). This difference is due to the increased volume of wind generation with the tight periods becoming more extreme

The IED scenario has a high energy unserved in 2020 as a result of the large number of plant being retired in a very short period of time, which leads to a particularly tight system margin for a year in this scenario. By 2025, the extra nuclear, coal CCS and wind being built eases the system tightness.

Figure 144 – Unserved energy



As to whether more intermittent generation lead to more unserved energy, our methodology in this study has been to build capacity so as to limit the number of periods with unserved energy per year to two periods – in practice there would be more for reasons outlined at the start of this section.

Additionally, since there are fewer periods with small capacity margins, for new entry to be viable there needs to be more value of capacity in those periods where the system is tight (see Section 2.5 – value of capacity). Prices also need to be peaky for existing plant (such as E class CCGTs) to recover their annual fixed costs[51].

6.8.4 What are the implications for the N-1 contingency?

As a further measure of system tightness in GB, be have looked at periods where the spare capacity is less than the largest load[52]. This again ignores the interconnection with SEM, which may overstate the number of periods, whereas we include the full capacity from the continent which may (in reality) understate the number of periods. This is shown in Figure 145 (again averaged across Monte Carlo scenarios). The increase follows a similar pattern to the unserved energy, with the greatest number of periods in 2016 and 2030.

---

51 This is a consequence of E class CCGTs running at low load factors, as with the closure of the oil steam plant, and a lack of new entry OCGTs, there is little below them in the merit order.

52 Note that this level of spare capacity would more than meet the low frequency response requirement, since there is also the reduction from reducing the system frequency to 49.5Hz from 50Hz.

Figure 145 – Periods when N-1 contingency is breached in GB

	Periods with margin less than Largest Load
2010	0.00
2015	0.00
2016	16.29
2020	6.50
2025	9.00
2030	13.71

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7. CONCLUSIONS

The study has focused on the following main question:

> *'How could the impact of intermittent generation, required to meet targets for renewables and decarbonisation of generation, affect the wholesale energy markets in GB and Ireland?'*

The conclusions to aspects of this question are summarised below.

Wind generation

How intermittent and how correlated is wind generation?

Unsurprisingly, there is considerable intermittency in wind generation, and a system with high levels of installed wind capacity will have significant variations to manage. Periods of very low wind generation (less than 5% of installed capacity) across either GB or Ireland will happen infrequently, but may last up to a few days; equally periods with very high wind generation will exist. Thus with our installed capacity assumptions for 2020, at the top 3 demand hours for the last 8 years, wind generation covers between 1% and 48% of demand in GB, and 3% and 82% of demand in the SEM. There is some variation of wind between different years, and with an assumption of 33GW of capacity in GB in 2020, a variation of between 83TWh and 93TWh in our eight Monte Carlo years – a variation of 12%. In the SEM, a higher annual variation of 21% is found in 2020 (with 6.1GW of wind capacity) due to the smaller size of the market – in generation terms this is between 14.6TWh and 17.7TWh.

There is some correlation (r^2 of 0.44) between wind in the SEM and in GB – both markets experience periods when average wind speeds (or wind generation) are either very high or very low together. With our deployment of wind turbines, there are no periods when wind generation in GB is high (over 90% of capacity) and at the same time low (below 10% of capacity) in the SEM. Unsurprisingly, different locations have different capacity factors, with offshore wind having much higher capacity factors than onshore wind.

The demand which must be met by non-wind capacity ('demand net wind') will be much more variable than the current demand profile. In GB in 2030, demand varies between 30GW and 70GW. However, demand net wind varies between zero and 65GW – a considerably greater range, as a result of the wind. In the SEM, there is a similar relationship – the range of hourly demand across the year is 5GW but demand net wind rises to 11GW by 2030.

As regards the hourly change in demand that the thermal system will face (ramping of demand net wind), in GB by 2020, the maximum hourly change that non-intermittent generation is found to face is 12.7GW up and 9.7GW down. By 2030, this has increased to 15.2GW up and 12.4GW down – thus 15.2GW of generation has to be brought on line for a single hour in the worst case scenario covered in our analysis. In the SEM, hourly ramping of demand net wind increases from 2.1GW in 2020 to 2.4GW in 2030.

Market prices

To what extent will market prices change, and how will volatility increase?

Increased penetration of wind is likely to make prices become much more 'peaky', with more periods with very high or very low prices. This is because the system will alternate between having too much capacity in periods with high wind speeds and high wind generation, and much tighter capacity when there are low wind speeds. Equally, the market arrangements in GB mean that some very high prices will be required if generation is to recover its fixed or investment costs. Market prices (principally in GB) may be negative at times as a result of renewable generation bidding at its marginal cost, which in GB (and Northern Ireland) might include the negative of the ROC value.

In the SEM, although prices will become more volatile than currently, they will not be as volatile as GB prices (setting aside the price floor and cap which are presently in place). There may be more low and zero priced periods than in GB due to the higher volumes of wind generation as a share of the market, but very few negative priced periods due to the market design (as a result of our assumed bidding of wind in ROI at zero). The extremes of high prices that GB may experience will be tempered in the SEM due to the Capacity Payment Mechanism, although GB will maintain a strong influence on SEM prices.

Across all the scenarios and years, there is a definite relationship that as wind generation increases, overall SMPs decrease. In GB, an increase of 10TWh of wind generation drops prices by about £0.6/MWh, whilst in the SEM an increase of 10TWh reduces prices by £7/MWh (€7.6/MWh). An increase of 10TWh of wind generation is a much greater share in the SEM than in GB, which explains the stark difference in the results.

Plant operation

How will plant load factors, starts and on times be affected by intermittency?

Load factors of conventional thermal plant are strongly impacted by high volumes of wind and baseload generation. In GB by 2020, load factors of older E-class CCGTs are below 10%, and newer F-class plant are under 60% whilst coal is at 50%. The main reason for this is the reducing 'space' for these plant to operate in – with rising volumes of baseload nuclear, CCS coal and biomass plant, and increasing volumes of low-cost intermittent generation, the running patterns of conventional plant by 2020 are increasingly the inverse of wind generation.

As regards running patterns, different plant types are affected in different ways. Newer F-class CCGTs have an increasing number of starts and a reducing period when they are on. In 2010, they typically run with 50 starts and are on for around 70 hours (3 days) – this will be running 5 days a week for some units and less for others. By 2020, the number of starts has increased to 90 a year, with units on for only 60 hours. By 2030, they start 120 times a year and run for about 25 hours. However, older E-class CCGTs have fewer starts. In 2010 they typically run two-shift, running for around 14 hours when on and starting 140 times a year. The number of starts then falls as the units are called upon to operate less and less, so that by 2020 they are starting only 20 times a year, and operating 13 hours each time.

In the SEM, the significant change in operating patterns for coal and CCGTs that was observed in the GB market is not seen even though wind penetration is much greater – this is mainly due to the existence of larger numbers of peaking plant. The less efficient peaking plant start 8-10 times a year and are on for 3 to 4 hours, with the advanced GTs starting 100 times a year with similar on times.

Overall, although the amount of CO_2 emitted from starting and part-loading plant does increase, it still remains a small share of the total, and unlikely to be of significance until the volume of zero carbon generation drops to very small levels.

New thermal generation

What is the outlook for new thermal generation?

The amount of new thermal generation required in the Core scenario is relatively low until 2030, primarily due to a low assumed demand growth until 2030, and very significant growth in renewables, and biomass.

In GB, the highest returns are to nuclear plant across all the scenarios. This is due to the absence of volume risk, which means that (unlike thermal plant) they are unlikely to have depressed load factors due to large volumes of wind. Across all scenarios, coal and CCS coal do not make sufficient returns to permit new build in our modelling. Conventional coal returns (on areal pre-tax basis) vary from 1% to 7% across the years, whilst CCS coal returns vary from 4.8% to 6.5% – all well below the indicative threshold of 8%-10% for required for investment.

Returns to CCGTs are highly variable in the Core scenario. When new CCGT build is required – primarily in 2030 – returns on plant rise sufficiently high to incentivise new build though the value of capacity. In years when there are sufficient system margins, plant returns drop substantially. In 2016, given much tighter system margins, IRRs on CCGTs rise towards new entry levels.

The Capacity Payment scenario leads to a very different outcome with regards to plant returns in GB. A payment for availability means that OCGTs become profitable, as they are in all scenarios in the SEM. CCGT returns are lower in this scenario, particularly from 2020 onwards: this is because payments from the capacity mechanism are not sufficient to recompense fully the higher fixed/capital costs of CCGTs (vs OCGTs).

In the SEM, there is a much greater consistency of outcome between scenarios due to the presence of the CPM. Thus returns to OCGT peaking plant remain above 8% in all scenarios and all years and are stable between 8-9%. This is because the vast majority of OCGT revenue comes from the Capacity Payment rather than varying wholesale prices since these plant run at very low load factors.

Returns to CCGTs in the SEM vary, and in particular are affected by the GB market. Hence if the GB market remains with the current BETTA market arrangements, returns in the SEM are high as a result of high wholesale prices ‘imported’ from GB – typically between 7% in lower years and 9% in higher years. Returns to Irish CCGTs are likely to be lower if there is a capacity payment mechanism in GB that suppresses peak price levels.

Wind revenue.

To what extent is wind revenue depressed by wind-on-wind competition, and how much might be de-loaded?

Wind revenue is depressed as more wind generation comes on the system. In the Core scenario for GB, in 2010, the wind capture price is higher than the TWA[53] price – as a

[53] Time-Weighted Average price – the simple average of all hourly prices in a year.

result of more wind generation in winter months when wholesale prices are higher. By 2016, this reverses, with wind capturing £5/MWh less than the TWA price, as increasing volumes of wind generation affect peak prices in particular. By 2030, wind captures £13/MWh less than market prices – a significant drop.

In the SEM, in the Core scenario, the effect of wind revenue cannibalisation is similar. In 2010, wind earns above the TWA price as in GB, but by 2020 earnings are £5/MWh (€5.4/MWh) below TWA prices, and by 2030 the gap is £12/MWh (€13/MWh).

There is substantial variation between different sites, with a spread between locations in GB of £5/MWh, with the highest revenue location in Stornoway (north Scotland) and the lowest in Rhyl on the north-Wales coast.

There is an approximate relationship between the amount of wind capacity in the GB market and the discount to TWA prices that wind generation obtains. With 10GW installed, wind captures approximately the TWA price. For every further 1GW installed, wind capture prices drop a further £0.25/MWh below the TWA price.

Reserve and response

How do requirements for reserve and response change and what are the implications?

As the installed capacity of wind in a market increases, the amount of response and reserve that needs to be held, and the significance of reserve and response, grows.

In GB, there is little difference in plant load factors due to the need to meet reserve and response requirements, but the trend is for the load factor of low load factor plant to rise slightly, and the load factor of high load factor plant to fall slightly compared with the 'market schedule'. There is an increase in the amount of plant being part-loaded to provide secondary frequency response. In the SEM there is a much larger change in plant load factors. There are particularly large increases in the load factors of peaking plant and coal plant, with the increase in peaking plant primarily due to the response constraints.

Four hour reserve in both markets becomes increasingly significant as wind penetration increases. Assuming an uncertainty of 25% in wind forecasting four hours ahead (the system operator plans for the worst case rather than the average), four hour reserve requirements in GB will rise from 5GW in 2010 to over 10GW by 2030 for January business days, to cover possible errors in wind forecasting. In the SEM, the requirement rises from 800MW to almost 1200MW by 2030. In the SEM, the four hour reserve is largely met from operating plant or peaking plant held in reserve. As a result, very little other plant needs to be kept warm (in a warm state so that it can synchronise within four hours). However, in GB, the market design and low plant returns in the Core scenario mean that very little peaking generation is built. This means that the four hour reserve requirement has to be met in a large part from plant that cannot respond when cold in a four hour timeframe, and would be required to be kept warm.

Interconnection and transmission

How important is interconnection and how are future flows impacted by wind?

The interconnection between GB and the SEM becomes of critical significance as the volume of installed wind generation increases. The larger the geographic area over which installed wind capacity is situated, the more constant and less intermittent the wind generation becomes; thus being heavily interconnected to a much larger market means that it is possible to smooth out the variation in wind generation. The SEM is a small market, both in terms of geographic spread and total demand, thus it becomes very susceptible to intermittent generation except through its interconnection to GB. However, building a large amount of interconnection has the effect of depressing its own revenues as prices equalise between markets, and this may make significant interconnection between markets difficult on a commercial-only basis.

Transmission flows between Scotland and England increase substantially in the Core scenario with the high volumes of renewable capacity built in Scotland. The Core scenario assumes significant reinforcement of existing capacity in 2016 which largely alleviates north-south constraints. Hence peak flows in 2020 reach our assumed capacity of 7.6GW, but only on a small number of days. The trend of flows from north to south remains, but over time, an increasing volume of flow transits into Scotland from England during low wind periods north of the border.

Between the ROI and NI, the Core scenario assumes a limited increase in transmission capacity from 400MW in 2010 to 700MW in 2015. As a result, there are significant constraints on flows from ROI to NI, due to relatively more volumes of wind generation built in ROI.

Market arrangements

Are existing arrangements fit for purpose?

Our modelling has assumed that existing standards of security of supply are maintained, and we have reviewed the value of capacity which is required to support the necessary investment.

However, we have identified that the existing relationship between system scarcity and the capacity component of market price will need to change in future in the absence of a formal capacity payment mechanism in GB. A key conclusion is that in order for security of supply to be maintained at current levels without significant involvement by the demand side, there would need to be a material increase in the capacity value accrued by peaking and low-merit generators, compared with that in evidence in today's market.

In SEM, the need for flexible generation is well served by the existence of a capacity payment mechanism. However, the extent of re-dispatch for reserve and frequency response compared with the market schedule suggests that some form of market pricing for the delivery of 'flexibility' is desirable to ensure that these services are adequately rewarded.

System security

How may system security change?

This study assumes as an input that system security is maintained, to a maximum of 2 hours loss-of-load expectation per year – thus we cannot judge whether system security is higher or lower with more wind. However, increasing wind penetration will lead to more periods with greater capacity margins. Although the number of very tight periods is similar between historical and future years, the capacity margin on average is much greater in 2016 and even more so in 2030. This reflects the extra generation that is required as backup for the periods where there is little or no wind generation. In GB in the Core scenario, the unserved energy (averaged over Monte Carlo scenarios) is 1120MWh in 2016, 240MWh in 2025, 1930MWh in 2030 and zero in other years, which is comparable with historical values. With increasing wind penetration, the amount of unserved energy increases although the number of periods remains the same – this is due to the increased volume of wind generation making the tight periods more extreme

ANNEX A – GLOSSARY

BETTA	British Electricity Trading and Transmission Arrangements	
CPM	Capacity Payment Mechanism	The system for remunerating capacity in the SEM
CCGT E CCGT F	Combined Cycle Gas Turbine E class and F class	Specifically two GE designs of CCGT. Used within the report to denote older (CCGT E class) and newer (CCGT F class) designs
CCS	Carbon Capture and Storage	
EPR	European Pressurised Reactor	
FGD	Flue Gas Desulphurisation	
GWh	Gigawatt hours	
IED	Industrial Emissions Directive	
	Intermittent	Technologies that are highly variable in their output – primarily wind, wave and tidal
LCPD	Large Combustion Plant Directive	
LOLE	Loss of Load Expectation	
MWh	Megawatt hours	
MOP	Merit Order Price	Price from modelling that only reflects direct short-run marginal costs of commodity prices (i.e. excludes start-up and part-load costs)
OCGT	Open Cycle Gas Turbine	
RES	Renewable Energy Sources/Supplies	
SEM	Single Electricity Market	The electricity market that covers both Republic of Ireland and Northern Ireland
SMP	System Marginal Price	Electricity price representing short-run marginal costs only (i.e. commodity prices, start-up and part-load costs)
SO Dispatch	System Operator Dispatch	Model run that accounts for reserve and response constraints as well as some interconnection constraints.
TWA	Time Weighted Average	TWA prices are the simple average (arithmetic mean) of all hourly prices in a year.

TWh	Terawatt hours	
UCTE	Union for the Coordination of Transmission of Electricity	
VOC	Value of capacity	
	Zephyr	Computer model used to simulations of GB and SEM markets for this study

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ANNEX B – LIST OF TABLES AND FIGURES

B.1 List of figures

B.2 List of tables

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IMPLICATIONS OF INTERMITTENCY – APPENDICES

A multi-client study

May 2009

IMPLICATIONS OF INTERMITTENCY – APPENDICES

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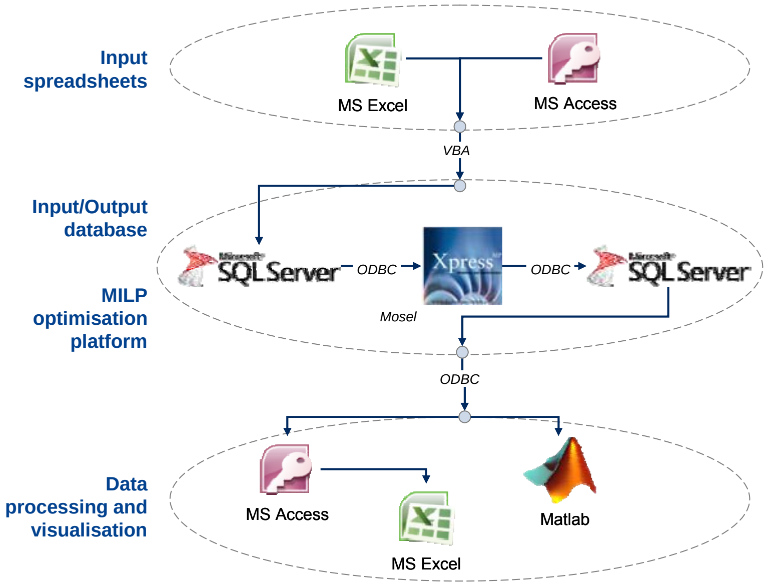
ANNEX A – DETAIL ON MODEL STRUCTURE AND METHODOLOGY

A.1 Model architecture

The electricity markets of GB and the SEM have been modelled using sophisticated computer model called Zephyr. Figure 1 illustrates graphically the structure and data flows of the Zephyr model.

Figure 1 – Zephyr model architecture



Source: Pöyry

Zephyr is a Mixed Integer Program (MIP) based around Xpress-MP[1] written specifically for this project, which schedules plant by optimising overall variable costs of generation[2], including start-up and no-load[3] costs across the GB and SEM electricity markets. Optimising start and no-load costs introduce binary[4] variables for whether a plant starts and whether it is on. For thermal plant, Zephyr includes some plant dynamics, including

- Minimum On Time (minimum number of hours a plant can stay on for once it starts generating).

1 Xpress-MP is a suite of mathematical modeling and optimization tools used to solve a range of problems. See http://www.dashoptimization.com

2 With ROCs counted as a negative cost. An additional term is added to take account of differences in the Value of Capacity between GB and SEM.

3 Additional fuel use due to the part-loaded efficiency of most power plants being less than the full load efficiency.

4 Variables which can take values 0 or 1 only.

- Minimum Off Time (minimum number of hours a plant must be off for once it has stopped generating before it can start generating again).
- Minimum Stable Generation (MSG) – the minimum level a plant which is on can generate at[5].
- The extent to which a plant can provide Reserve and/or Low Frequency response.

There is the option in the model to partially model ramping (restricting output in the first and last periods of operation) but for reasons of run time this was not implemented for this project. The thermal plant were put into the model by grouping the plant into bands of plant with near identical properties, and then modelling all plants in a band as identical. This approximation significantly reduces the size of the problem.

For Pumped Storage (PS) capacity we modelled a maximum generation, a maximum pumping, maximum and minimum reservoir levels, and the contribution of PS to reserve and response. For simplicity we forced the PS reservoir to be full at 6am on Monday mornings. Pumped storage parameters include an efficiency (units of generation for each unit of pumping) and a pumping ratio (ratio of maximum allowed pumping to maximum allowed generation).

Zephyr models at an hourly resolution, 365 days per year (e.g. 8760 periods per year). For each year, eight Monte-Carlo scenarios (different wind, availability and demand patterns[6], based on historical years 2000 - 2007) were run. The optimizations were done over a month. For inter-temporal constraints, such as take-or-pay constraints and LCPD restrictions, the annual constraints were turned into cumulative monthly constraints by doing an initial annual LP[7] run (ignoring start-up and no-loads costs).

Interconnectors with continental Europe were modelled using border prices (SMPs) calculated from a Mixed Integer version of Eureca[8] which optimised start-up and no-load costs, and included plant dynamics in a similar manner to Zephyr. This was however, still a sample day model, as extending this model is outside the scope of this study.

Zephyr can be run in two modes, Market Schedule and SO (System Operator) Dispatch. These are sometime referred to as Unconstrained and Constrained runs respectively. The Market Schedule run aims to simulate what the market (day-ahead or at gate closure) would produce for plant operation and prices. The SO Dispatch simulates additional actions that would be required to cover reserve and response as well as transmission constraints between Scotland/E&W and Northern Ireland/ROI.

A.1.1 Market Schedule

The purpose of this run is to determine SMPs, and to assess the profitability of new entry (and existing plant). This run did not include reserve and response constraints, and no within-market transmission constraints. SMPs were calculated in three stages:

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5 As ramping is not been modelled, generating below MSG when ramping up or down has not been considered.

6 Scaled up to the 2008 profile using the trend growth rate, and then scaled to the year being run using assumed growth rates. The base profile was modified for DDR and DSR sensitivities.

7 Linear Programming, with all variables continuous.

8 Pöyry Oxford's standard electricity model

i) Calculating Shadow Price (Merit Order Price or MOP) for each market. This is the cost of meeting one additional unit of demand from fuel and direct variable costs, and does not include increased start-up or no-load costs.

ii) Add a component to represent No-Load costs, where necessary/appropriate.

iii) Add an additional component to prices to ensure that for each day, no plant makes a loss (excluding fixed costs, but including start-up costs). The main driver of this component is plant start-up costs. This is done iteratively – the plant making the largest per MWh loss is looked at first. Where possible we assume that plant running at or below MSG have little impact on the wholesale price, so try to add this component in periods where the loss making plant is running above MSG[9].

The Value of Capacity component is then added to the SMP to produce the wholesale price. For details of the assumed Value of Capacity function, see the main report.

For steps ii) and iii) if the same plant is marginal in both GB and SEM (i.e. when the interconnector constraint does not bind), the components are added to both markets, otherwise just to the market in question. While plant operation is output from the Market Schedule, the SO Dispatch run is likely to give operating patterns closer to that seen in reality.

A.1.2 SO Dispatch

The SO Dispatch run includes internal transmissions constraints (Scotland to/from England, and Northern Ireland to/from Republic of Ireland), low frequency response requirements and reserve requirements. We are modelling the requirement that the system is capable of providing the required reserve/response, not the operation of the reserve/response. As a result there is not difference between 'forecast' and 'outturn' and no uncertainty over demand, wind generation or availability. However, there is provision for this uncertainty. For this reason it was decided to not model high frequency response, since deloaded wind is always a possible (albeit possibly expensive) option. In SEM Inertia constraint is also modelled.

Generally the reserve and response constraint make far more difference to plant operating patterns in SEM than in GB (see the main report for details of assumptions for provision and requirements for reserve/response).

A.2 Plant technical assumptions

As the aim of the study was not to look at the operation of specific plant in high detail, but to look at long term trends, we divided the power plants in the model into a number of categories[10], and used the same parameters for all plant in the category. This also avoids issues about some of the differences between current parameters relating to short-term issues. Our plant parameter assumptions were based on http://www.bmreports.com/servlet/com.logica.neta.bwp_PanBMUData, publicly available NERA data and discussions/correspondence with study Founder members. Our assumptions are summarised below.

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9 Clearly if during a period of operation a plant never runs at greater than its MSG this component will need to be added in those periods.

10 Splitting plants by features such as fuel, technology, efficiency, FGD/LCPD issues, approximate efficiency and capacity.

Table 1 – Technical parameters for different thermal plant types

Type	No-Load fuel use, GJ/GW/h	Start-Up fuel use, GJ/GW (Hot start)	Start-Up Maint., £/GW	MSG[11] (%)	Min. On Time (hours)	Min. Off Time (hours)	VOWC, £/MWh
Coal	846	1360 Coal + 2400 LSFO	14720	30%	4	4	1.35
NewCoal	846	1360 Coal + 2400 LSFO	14720	90%	8	8	1.35
Nuclear	-	-	16000	90%	1[12]	10	2.00
Oil_steam	846	4680	14720	38%	3	2	1.20
CCGT_E (GB only)	1200	3463	13250	53%	5	5	0.70
CCGT_F (GB only)	1200	3463	13250	60%	4	4	0.70
CCGT_SEM	1200	3463	13250	50%	4	4	0.70
Gas_steam	846	4680	13250	38%	3	2	1.20
CHP	1200	3463	13250	53%	5	5	0.70
CCSCoal	846	1360 Coal + 2400 LSFO	14720	65%	8	8	9.60
Biomass	846	1360 Biomass + 2400 LSFO	13250	53%	5	5	-1.5 ROC
Advanced OCGT	745	2194	0	50%	1	1	2.70
GT_1	1588	1937	12000	90%	1	1	0.70
GT_2	1588	1937	12000	35%	1	1	0.70

Source: Pöyry Energy Consulting, discussions/correspondence with Founder members, NERA, GE, DECC

Table 2 – Plant type description and comments

Type	Description/Comments
Coal	Existing Coal and Peat plants. Peat plants are assumed to run fully loaded in the unconstrained run. In the constrained run this is relaxed slightly so the Peat units can provide low frequency response.
NewCoal	New conventional coal plant (eg Kingsnorth).
Nuclear	All Nuclear plants. New nuclear plant (EPRs for example) are likely to be more flexible, but this has not been modelled.
Oil_steam	Oil-fired steam turbines.

11 Minimum Stable Generation – also known as Stable Export Limit (SEL)

12 Given the long Minimum off time, the minimum on time is very unlikely to ever be an issue, so we have not taken a view on it.

CCGT_E (GB only)	Older CCGTs (mainly E class) in GB.
CCGT_F (GB only)	Newer CCGTs (mainly F class) in GB.
CCGT_SEM	Irish CCGTs.
Gas_steam	Gas-fired Steam turbines.
CHP	Small scale CHP.
CCSCoal	90% capture efficiency assumed. VOWC includes capture costs.
Biomass	does not include co-firing, which is not modeled.
Advanced OCGT	Advanced Aero-derivative type turbine, eg LMS100.
GT_1	Old small OCGTs (largely in GB).
GT_2	Newer (typically larger) OCGTs. New units are assumed to run on Gasoil to avoid gas connection costs.

Source: Pöyry Energy Consulting, EDF, GE

The reasons for differing MSG between GB and SEM for CCGTs relates to different rules concerning NOx emissions in the two markets. For Nuclear, although our start-up costs may not appear that high, the main issue is having to stay off for 10 hours, since prices are unlikely to be very low for 10 consecutive hours. For existing nuclear plant reliable technical parameters are hard to find, since currently nuclear plants in GB would never not generate for economic reasons. New nuclear designs remain untested.

A.3 Market dispatch (constrained run) assumptions

A.3.1 Introduction

In the market dispatch/constrained run we model within-market transmission constraints). We also model the capability to meet:

- **Low Frequency (LF)** response requirements (primary in SEM, secondary in GB)[13].
- **4 hour reserve requirements**.
- **Inertia** (SEM only).

Low Frequency Response is the capability to respond to a drop in system frequency, typically caused by a trip (forced outage) of another unit. Typically primary response covers timescales up to 30 seconds from the outage, while secondary response covers timescales from 30 seconds to 30 minutes from the outage.

Reserve is the ability to cover unforeseen increases in generation requirements[14], over timescales longer than secondary response. In this study we model the 4 hour requirement capability (ability of increase output with 4 hours notice).

[13] The assumption is that these are the most important – when secondary is met in GB primary will normally be met, and when primary is met in SEM secondary will normally be met. The difference in what is most important relates to the relative sizes of the two markets.

[14] For example due to higher than expected demand, lower than expected wind availability, plant outages (beyond the low frequency response requirements)

We have chosen not to model High Frequency response[15] provision, since we are only modelling capability to provide response and it is always possible (although not necessary good economics) to de-load wind. Consequently a High Frequency requirement would have little effect.

A.3.2 Low Frequency (LF) response

A.3.2.1 Great Britain

Secondary response

In GB the secondary response requirement each hour is modelled as:

1.15 * LargestLoad – DemandContribution – 0.0115 * Demand

The requirement is for GB as a whole – there are no separate requirements for E&W or Scotland, and no sharing of requirement/provision with the SEM. This also applies to both markets for all reserve/response constraints.

LargestLoad is a fixed number (i.e. not dependent on what is generating at the time) which represents the largest infeed loss that could be expected (the 'N-1' contingency). Currently it is 1260MW, corresponding to the total capacity of Sizewell B. This will rise to 1660MW when EPRs are built (2020 is the first modelled year with EPRs). While the EPR capacity is 1600MW, the definition of largest load is slightly different to that of electrical capacity. The demand contribution assumed is 100MW. Demand * 0.0115 represents ~ 2.3%/Hz demand 'response' for 0.5Hz[16].

For example, at a time of high demand of 60GW, the secondary response requirement will be 660MW pre-2020 and 1120MW post-2020 once EPR are built.

Pumped storage

The contribution from pumped storage is:

PumpingConsumption + 0.5 * (UnitsGenerating * UnitCapacity – PSGeneration)

The maximum pumping consumption is UnitCapacity * UnitsPumping/PumpingRatio[17]. For simplicity we have modelled the GB pumped storage capacity as 6x300MW units. This slightly understates the installed capacity, but in reality there are outages. An important point is that when pumped storage is not generating or pumping it can provide 900MW[18] – between the 660MW (pre-EPR) and 1120MW (post-EPR) as discussed above.

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[15] Response to a rise in system frequency, for example due to a sudden drop in demand.

[16] In GB under normal circumstances the system frequency must be within 0.2Hz of 50Hz. Between 0 and 30s after an outage the frequency is allowed to drop to 49.2Hz. Between 30s and 30m from the outage the frequency must be above 49.5Hz. This lowers the requirement for a sudden increase in power plant output.

[17] The ratio of the rates a pumped storage facility can pump and generate.

[18] In reality the units which are not pumping or generating would need to be generating above a minimum level to provide response (MSG of PS), but this effect has not been modelled.

In GB it is assumed that thermal plants (excluding nuclear) which are generating can provide 55% of their headroom[19] towards meeting the Low Frequency requirement. We assume 15% of de-loaded wind can provide LF response.

A.3.2.2 SEM

In the SEM the primary response requirement is:

0.8 * LargestLoad – 0.02 * Demand

The largest load remains at 450MW throughout[20]. Hence in a period with relatively high demand of 6GW, the residual primary response requirement is 240MW. However, the contribution of the pumped storage units when not generating or pumped is only 35MW (see below).

The contribution from pumped storage is :

Min (PumpingConsumption + 0.5 * (UnitsGenerating * UnitCapacity – PSGeneration), PumpingConsumption + 0.12 * UnitsGenerating * UnitCapacity)

The SEM pumped storage is modelled as four 72.5MW units.

The contribution from a thermal unit is:

Min (AvailableCapacity * On * PrimCont, PrimSlope * Headroom * On)

Where On is 1 if the unit is generating and 0 otherwise and PrimSlope and PrimCont are unit specific parameters.

PrimCont is 10% for OCGTs and 5% for other units. For new generic units it is assumed that PrimSlope is 70% for CCGTs and 100% for OCGTs. 50% is assumed for the new CCSCoal unit. We assume thirty percent of deloaded wind can provide low frequency response[21].

Table 3 – PrimSlope Parameters for existing SEM power plants

Plant	PrimSlope	Plant	PrimSlope
Aghada_AD1	100%	Marina_MRT	100%
Aghada_AD8	100%	Moneypoint_MPFGD1	50%
Aghada_AT1	100%	Moneypoint_MPFGD2	50%
Aghada_AT2	100%	Moneypoint_MPFGD3	50%
Aghada_AT4	100%	Northwall_NW4	100%
Aghada_ATCCGT	100%	Northwall_NW5	100%
Aughinish_AU1	100%	Poolbeg_PB1	100%
Ballylumford_BGT1	100%	Poolbeg_PB2	100%
Ballylumford_BGT2	100%	Poolbeg_PB3	100%

19 Headroom is the gap between a unit's generation and its available capacity.

20 450MW is a relatively small size for a new CCS unit, so there may be some advantages to this increasing.

21 The higher figure than GB reflects the differences in primary and secondary response timescales.

Ballylumford_BN10	70%	Poolbeg_PBC	70%
Ballylumford_BN2	70%	Rhode_RH1	100%
Ballylumford_BNC4	100%	Rhode_RH2	100%
Ballylumford_BNC6	100%	Shannonbridge_SH4	100%
Coolkeragh_CK3	70%	Synergen_DB1	70%
Coolkeragh_CK4	70%	Tarbert_TB1	100%
Edenderry_ED1	100%	Tarbert_TB2	100%
GreatIsland_GI1	100%	Tarbert_TB3	100%
GreatIsland_GI2	100%	Tarbert_TB4	100%
GreatIsland_GI3	100%	Tawnaghmore_TW5	100%
Huntstown_HN2	100%	Tynagh_TYN1	70%
Huntstown_HNC2	100%	Whitegate_WG1	70%
Kilroot_KGT1	100%		
Kilroot_KGT2	100%		
Kilroot_KRFGD1	100%		
Kilroot_KRFGD2	100%		
Lanesboro_LA8	100%		

Source: Pöyry Energy Consulting

A.3.3 Four hour reserve

We also modelled four hour reserve which is the capacity that would have been capable of providing reserve given up to four hours' notice and is typically required for inaccuracies of demand and wind forecasting, as well as unexpected unit outages. The assumption was that all capacity (other than nuclear) were capable of providing reserve – we did not model warming costs to keep units sufficiently warm that they were capable of generating at full load within four hours.

Unlike low frequency reserve, four hour reserve can be shared between GB and SEM. There are therefore three requirements, one covering GB (including free SEM interconnection), one covering SEM (including free GB interconnection) and one covering both markets combined.

A.3.3.1 GB

Initially the GB requirement is:

> Summer: 5640MW – 500MW – 0.021 * Demand + WindUncertaintyfactor * Max(WindOutput – 300MW,0)

> Winter: 5390MW – 500MW – 0.021 * Demand + WindUncertaintyfactor * Max(WindOutput – 300MW,0)

Note that these requirements include the low frequency requirement. Therefore the requirements will rise by 460MW once EPRs are commissioned. 500MW is the non-energy market reserve.

The reserve and response requirement can be met from a number of sources:

- Pumped Storage. Here the full available output[22] can be utilised, i.e. PSCapacity – PSGeneration + PSConsumption.
- Deloaded wind again provides a 15% contribution.
- All headroom of thermal units (other than nuclear), including those that are not generating.
- Any scope to increase interconnection flows from SEM.

We have not explicitly considered sharing of reserve with continental Europe. However, it is always possible to increase flows from continental Europe up to the maximum import capacity, which will result in GB plant being deloaded, so increase reserve provision.

A.3.3.2 SEM

Here the requirement is

Max (800MW, WindUncertaintyFactor * WindGeneration) – 50MW – 0.02*Demand

The contributions are from the same sources as in GB, except that deloaded wind provides a 30% contribution, and it is scope to increase flows from GB.

A.3.3.3 Overall (GB and SEM combined)

Here the requirement is just the sum of the GB and SEM requirements, but excluding interconnection components.

A.3.4 Inertia (SEM only)

In SEM we also model an inertia constraint. This is a minimum level of thermal units which need to be generating in any period. Our (constrained) scenarios all assume this limit is 10 units. Since we are not modelling plant availabilities on a unit by unit basis, the contribution of a unit to the Inertia requirement is the availability[23].

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22 There would need to be enough water in the PS reservoirs to provide the reserve for long enough for other sources to take over. This is not explicitly modelled, but we do assume a minimum storage level corresponding to one hours output – this should go a long way towards meeting the requirement.

23 Not taking any reduction/increase in availability due to ambient factors into account. For a band of identical plants, this would be the proportion of units in the band which were available in the historic year corresponding to period in the Monte Carlo scenario being modelled.

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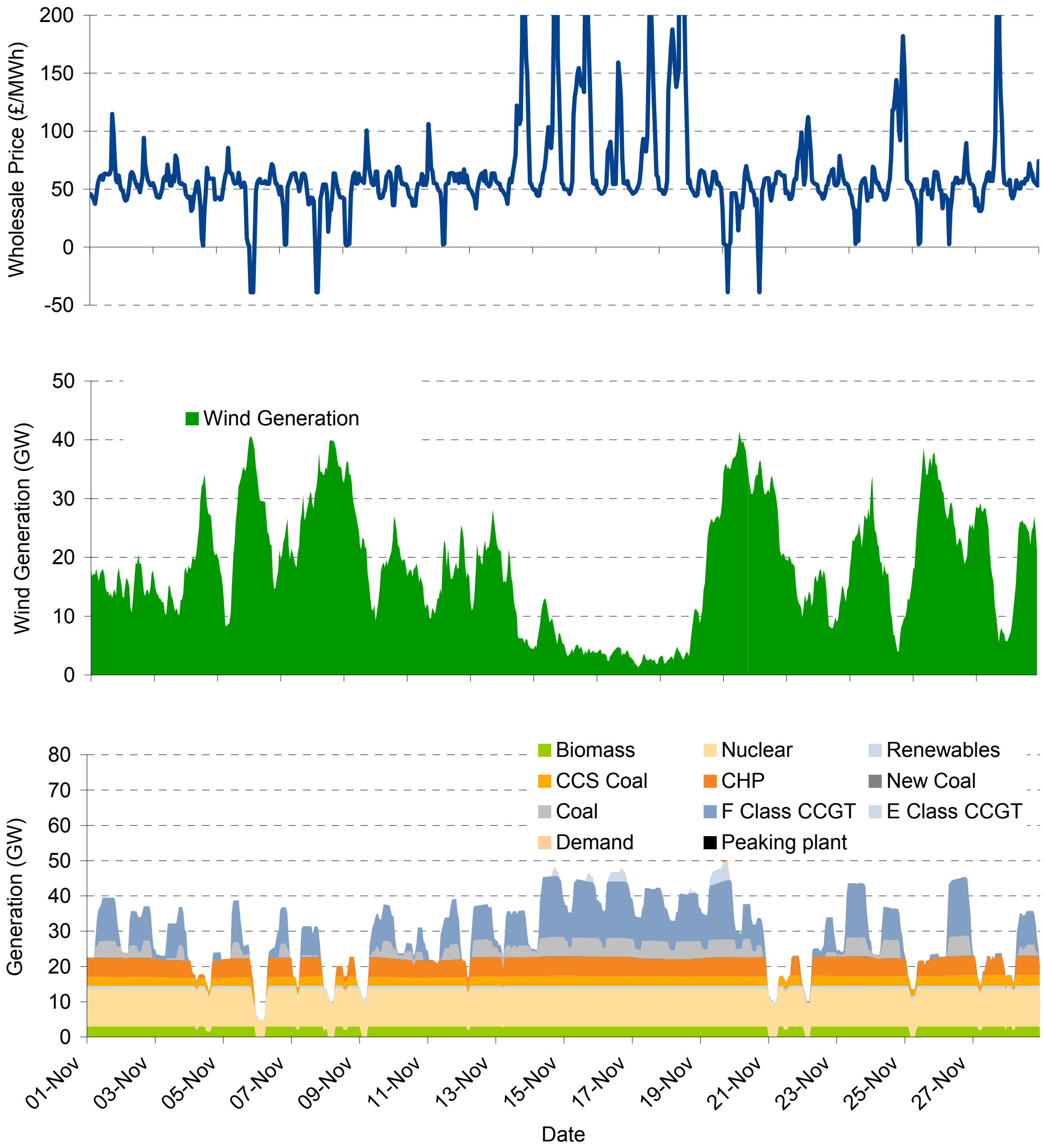
ANNEX B – DETAIL ON HOURLY GENERATION AND PRICES

The following charts give an hourly snapshot of the GB and SEM systems based on the Market Schedule runs for a month period, showing wholesale prices, wind generation and generation from other plant.

In November 2001, the UK was mainly dry, mild and anticyclonic, with the SE of England experiencing extremely dry and sunny conditions. After a warm start, there was a little snow during the second week in eastern England. The third week was mostly dull and gloomy. Conditions changed to wet and unsettled in the last week of the month, then became very mild at the end. In the electricity and gas markets, the demise of Enron had a marked effect on both the UK and Continental markets. After several financial institutions downgraded Enron to junk status, many of the players of the gas markets were forced to reassess their trading position.

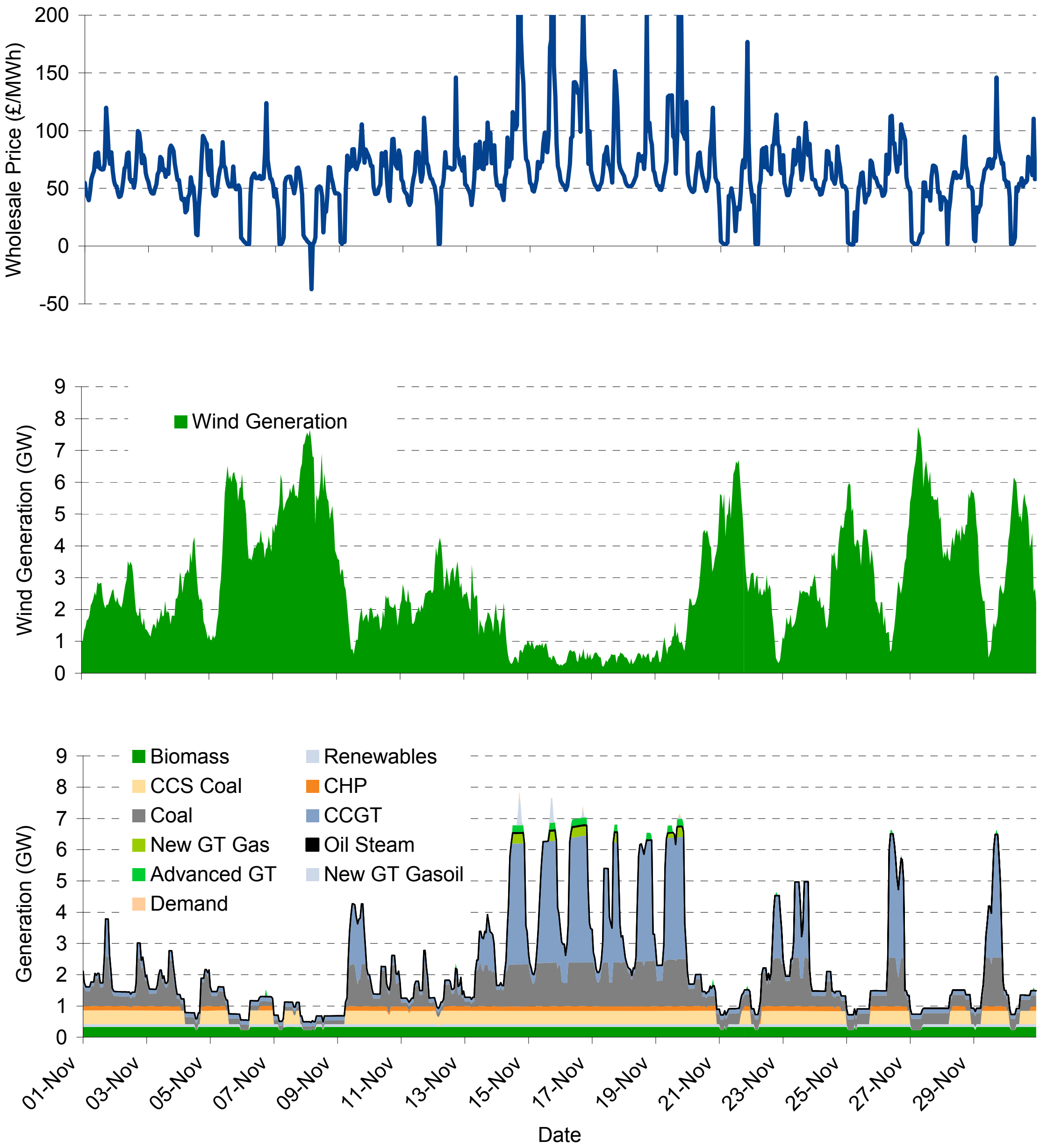
Figure 2 – GB system profile in 2030 based on November 2001



Note Chart of GB prices cut at zero and 200

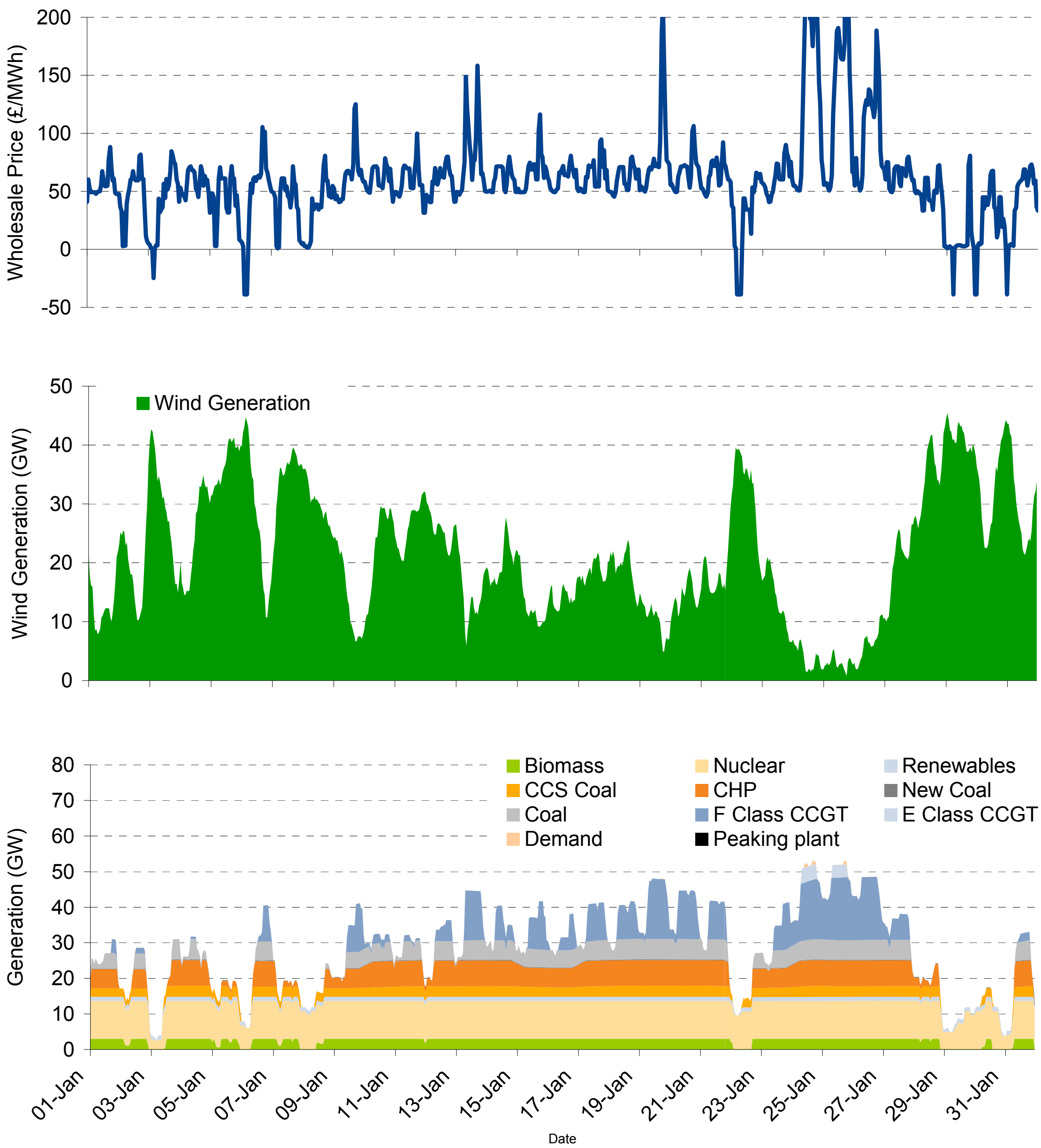
Figure 2 shows how the GB electricity markets reacted during 2030. There are periods of nuclear plant being turned down to permit very high volumes of wind generation – particularly from 21 November. A week earlier, wind generation dropped below 5GW continuously for 4 days which led to a period of very high prices.

Figure 3 – SEM system profile in 2030 based on November 2001



The SEM has a similar pattern to GB in the middle of the month, with very low wind generation and very high prices. By 21 November, almost all plant on the system are curtailed for the wind generation. The end of the month shows very significant variation in thermal generation, with CCGTs being brought on to cope with short periods of low wind, followed by periods with high wind generation.

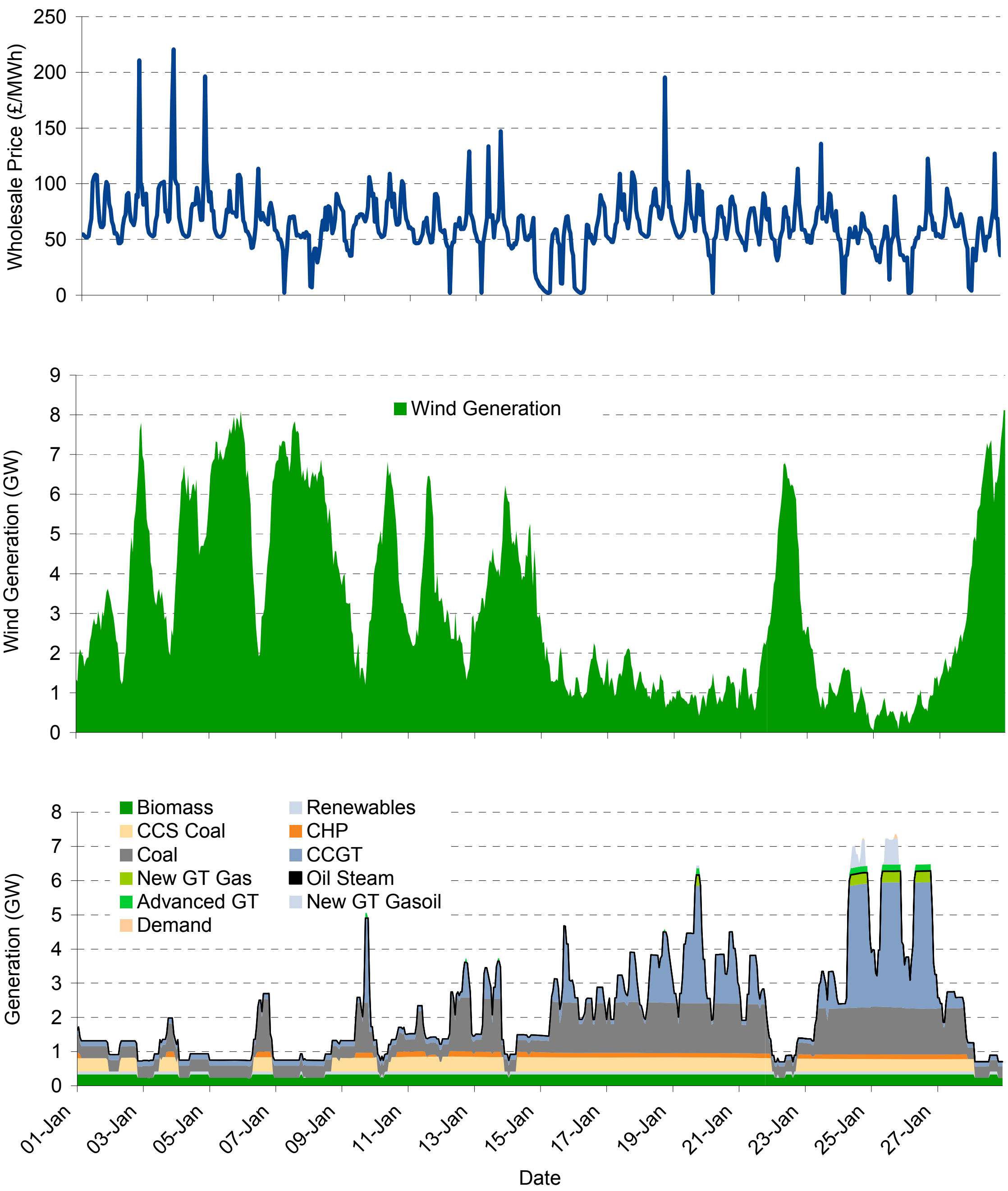
Figure 4 – GB system profile in 2030 based on January 2000



The UK was dry and sunny and generally mild in January 2000. During the month, the country experienced 53 mm of rainfall and an average of 2.23 hours of sunshine per day. The second half of the month was however predominantly cold and frosty, though the closing days were very mild with severe gales in North of England and Scotland.

The most significant event was three days of extremely low wind generation from 25 January, followed by some of the highest wind generation experienced that year. This leads to significant curtailment of nuclear plant and negative prices.

Figure 5 – SEM system profile in 2030 based on January 2000



In the same period, the SEM experienced even greater volatility with a period of a week of low generation from 16 January onwards.

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ANNEX C – DETAILED RESULTS FROM SCENARIOS

The following section gives more detailed results from the scenarios and sensitivities that have been run as part of this study. The detailed results are only from the Market Dispatch runs. The following notes give more context on the calculations.

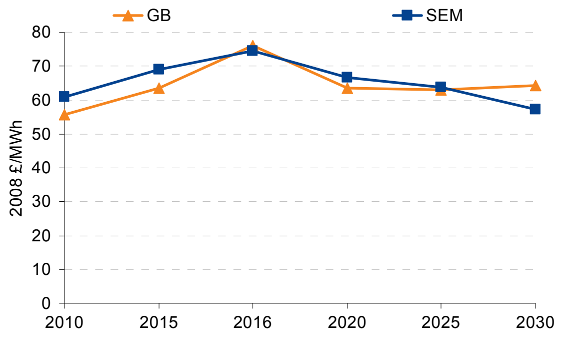
- **Annual wholesale price.** This is the time-weighted average (TWA) wholesale market price (i.e. the simple average of all prices in the period).
- **Internal rate of return (IRR).** This is calculated pre-tax real, with assumptions as shown in Table 4 It should be noted the IRRs are calculated for plant commissioned in that year (whether or not plant are actually built) and then run within the model. Thus the IRR of a plant commissioned in 2010 reflects model prices for 2010, 2015, 2016, 2020,and 2025 (assuming a 15 year lifetime). Post-2030, all revenues are assumed to be constant at the 2030 level.
- **End user cost.** This represents the cost of end-users (customers) for the cost of wholesale electricity and renewable subsidies. It is calculated by multiplying demand by price for each hour of the year, and adding on renewable subsidies.
- **System cost.** This reflects the cost incurred by generators for variable costs (including starts and part-loading) and annual fixed costs.
- **Wind curtailment**. This is the amount of wind de-loaded, as a result of economic reasons and does not include wind curtailment due to transmission or system operation reasons.
- **Carbon emissions and carbon intensity**. These reflect the emissions from all plant in the relevant market including those for starts and part-loading. Carbon intensity is the carbon emissions per unit of electricity generation.
- **Investment costs.** This represents the cost of building new plant. The majority of the cost is in renewables or 'non-market determined' investment such as nuclear and coal CCS.
- **Lost load (also described as energy unserved).** This represents the energy (demand) requirement that is not met during the year in MWh.

Table 4 – Plant economic assumptions

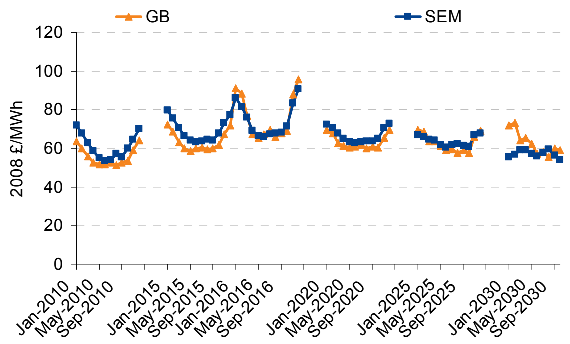
	Capital Cost (€/kW)	Annual Fixed Cost (€/kW)	Econ. lifetime	Econ. build time
Nuclear	2500	£120 (includes variable costs)	25	5
CCSCoal	2100	50	20	4
Coal	1500	36	20	4
CCGT	750	32	20	2
New GT	430	29	20	2

C.1 Core scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.8	63.6	76.0	63.4	62.9	64.2
SEM	60.9	69.1	74.4	66.7	63.7	57.3
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	66.3	74.5	80.2	71.9	68.7	61.7

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	63.6	72.4	91.0	69.5	69.6	72.1
GB - May	51.7	58.8	65.5	60.4	61.5	62.2
GB - Sep	52.7	59.9	67.7	61.1	59.2	60.1
SEM - Jan	63.6	72.4	91.0	69.5	69.6	72.1
SEM - May	51.7	58.8	65.5	60.4	61.5	62.2
SEM - Sep	52.7	59.9	67.7	61.1	59.2	60.1

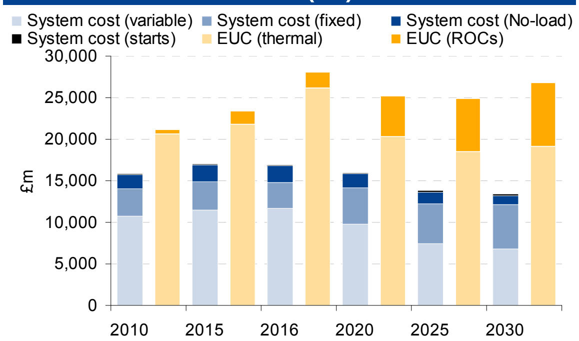
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.2%	11.6%	11.8%
CCSCoal	N/A	N/A	N/A	6.4%	6.5%	6.5%
Coal	N/A	N/A	3.6%	2.7%	3.4%	3.9%
CCGT_F	5.0%	7.6%	8.2%	6.2%	8.0%	9.4%
OCGT	<0	<0	<0	<0	<0	<0

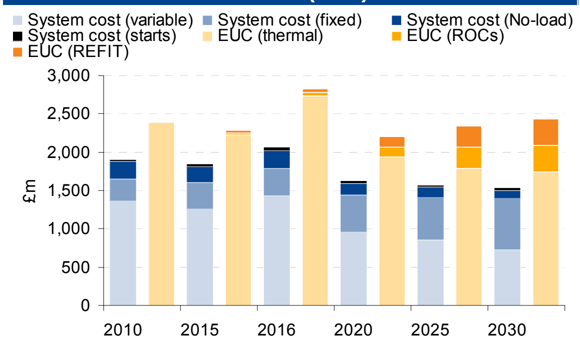
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	8.1%	8.1%	7.0%	6.5%	6.3%
CCSCoal	N/A	N/A	N/A	N/A	N/A	4.4%
LMS100	N/A	2.6%	3.6%	6.5%	6.6%	6.7%
OCGT (Gasoil)	8.9%	9.2%	9.3%	8.6%	8.5%	8.8%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

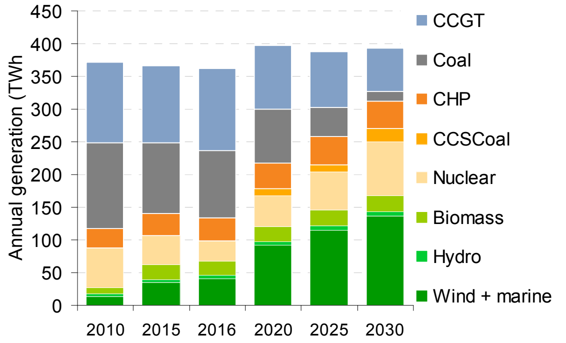
		2010	2015	2016	2020	2025	2030
System cost	Variable	10798	11530	11672	9757	7489	6798
	Fixed	3281	3414	3129	4390	4730	5317
	No-Load	1636	1925	1991	1662	1401	1087
	Starts	134	158	142	172	176	177
EUC	Thermal	20652	21776	26151	20275	18526	19139
	ROCs	532	1599	1944	4910	6374	7655

End user cost vs annual cost (SEM)

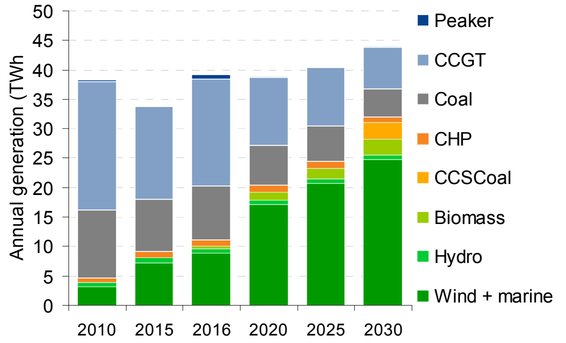
		2010	2015	2016	2020	2025	2030
System cost	Variable	1361	1257	1431	959	849	728
	Fixed	290	348	352	481	558	662
	No-Load	226	209	237	158	137	110
	Starts	22	32	43	31	30	30
EUC	Thermal	2385	2223	2740	1935	1786	1737
	ROCs	14	31	45	134	276	351
	REFIT	25	63	79	180	253	312

C.1.1 Core scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.0	6.8
Biomass	9.9	22.5	22.5	22.5	24.4	24.5
Nuclear	60.2	44.5	30.4	47.7	58.7	82.8
CCSCoal	0.0	0.0	0.0	10.5	10.3	19.6
CHP	29.2	34.0	34.9	38.6	42.8	42.3
Coal	131.8	108.5	102.5	82.3	44.6	15.2
CCGT	123.0	117.3	125.9	97.6	86.0	66.0
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.8	366.1	361.9	397.0	388.1	393.5

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.8
CHP	0.7	1.1	1.1	1.2	1.1	0.9
Coal	11.6	8.8	9.1	6.8	6.1	4.9
CCGT	21.7	15.8	18.1	11.6	9.9	7.0
Peaker	0.3	0.2	0.7	0.2	0.2	0.1
Total	38.2	34.0	39.2	38.9	40.6	44.0

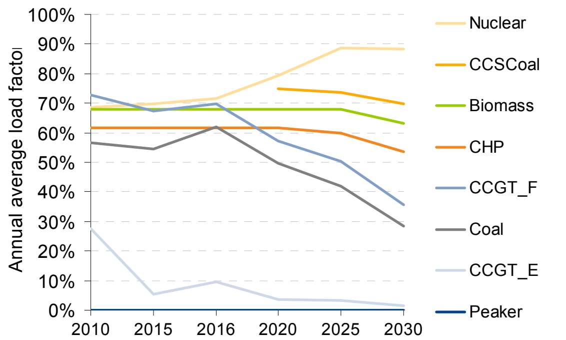
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	9.4%	11.3%	23.3%	29.7%	34.7%
Hydro	1.3%	1.3%	1.4%	1.3%	1.6%	1.7%
Biomass	2.7%	6.1%	6.2%	5.7%	6.3%	6.2%
Nuclear	16.2%	12.1%	8.4%	12.0%	15.1%	21.0%
CCSCoal	0.0%	0.0%	0.0%	2.6%	2.7%	5.0%
CHP	7.8%	9.3%	9.6%	9.7%	11.0%	10.7%
Coal	35.4%	29.6%	28.3%	20.7%	11.5%	3.9%
CCGT	33.1%	32.0%	34.8%	24.6%	22.2%	16.8%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	16.9%	18.8%	30.3%	37.5%	42.6%

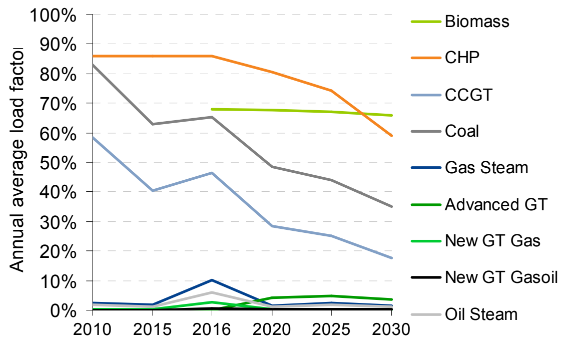
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.3%	21.4%	22.5%	43.9%	50.9%	56.3%
Hydro	2.1%	2.3%	2.0%	2.0%	1.9%	1.6%
Biomass	0.0%	0.0%	1.2%	3.5%	4.6%	6.3%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	6.5%
CHP	1.8%	3.3%	2.9%	3.0%	2.7%	2.0%
Coal	30.4%	26.0%	23.3%	17.5%	15.1%	11.2%
CCGT	56.7%	46.5%	46.2%	29.8%	24.3%	15.8%
Peaker	0.7%	0.5%	1.9%	0.4%	0.5%	0.3%
RES %	10.4%	23.7%	25.7%	49.4%	57.4%	64.2%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

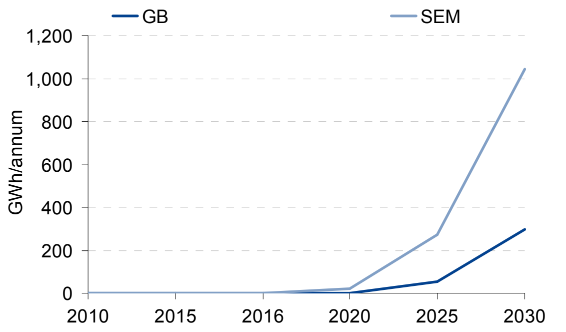
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	63%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	28%	5%	10%	4%	3%	1%
CCGT_F	73%	67%	70%	57%	50%	36%
Coal	57%	55%	62%	50%	42%	28%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

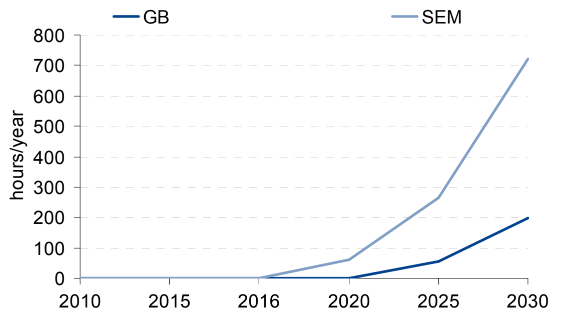
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						74%
CHP	86%	86%	86%	81%	74%	59%
Coal	83%	63%	65%	49%	44%	35%
CCGT	58%	41%	46%	28%	25%	18%
Gas Steam	2%	2%	10%	2%	2%	2%
Advanced GT	<0.1%	<0.1%	<0.1%	4.2%	4.8%	3.6%
New GT Gas	0.2%	0.2%	2.6%	0.2%	0.2%	0.1%
New GT Gasoil	<0.1%	<0.1%	0.5%	0.2%	0.2%	0.2%
Oil Steam	1.7%	1.1%	6.0%	1.3%	1.8%	1.3%

C.1.2 Core scenario page 3

Wind curtailment



Shedding periods



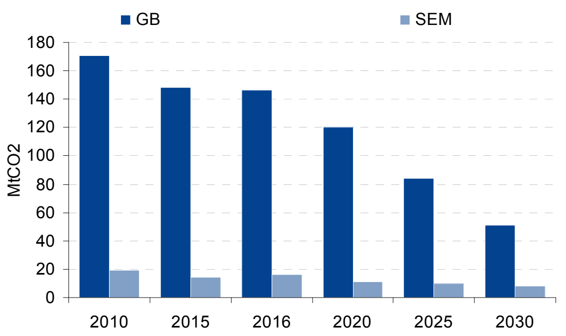
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	297
SEM	0	0	0	21	272	1041

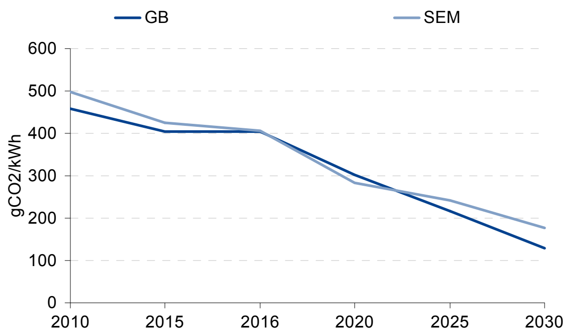
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	198
SEM	0	0	0	61	264	723

Carbon emissions



Carbon intensity



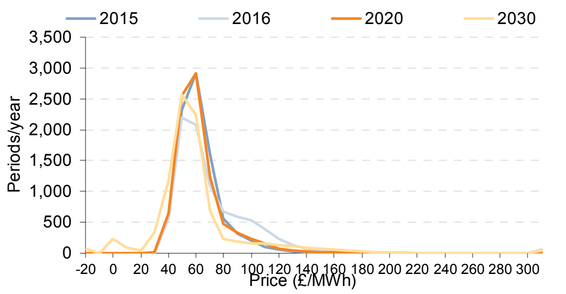
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	148	146	120	84	51
SEM	19	14	16	11	10	8

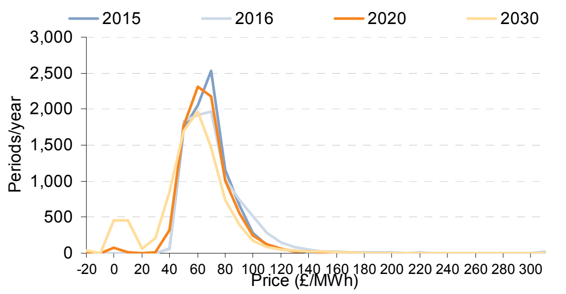
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.1	404.2	403.6	302.1	215.8	129.1
SEM	497.0	424.2	406.3	283.5	241.5	177.6

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

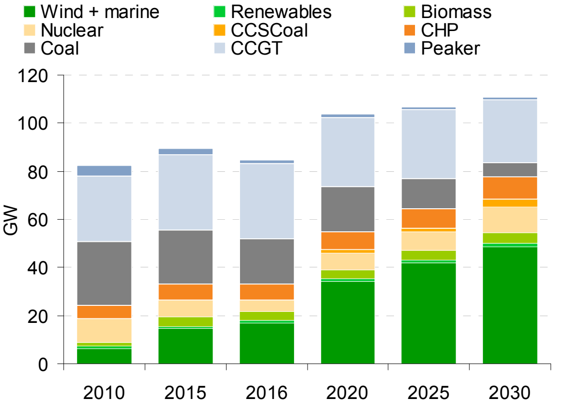
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	5	101	305
0-20	0	0	0	4	27	122
20-50	5114	2889	2752	3225	3447	4080
50-100	3528	5602	4942	5170	4696	3482
100-200	113	259	959	337	458	697
>200	6	10	107	20	31	75

Price distribution (SEM)

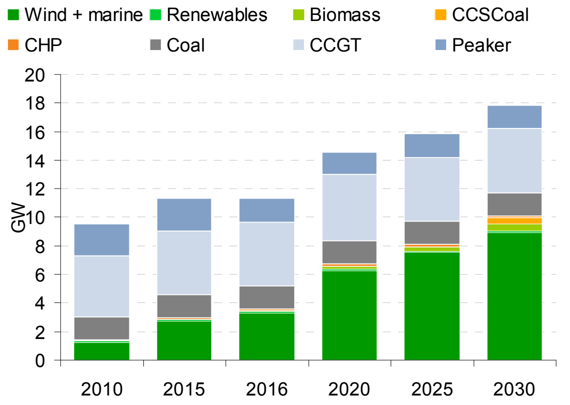
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	73	250	487
0-20	0	0	0	15	109	511
20-50	3546	1801	1897	2106	2338	2753
50-100	5094	6696	6165	6292	5761	4729
100-200	116	255	649	259	283	269
>200	5	8	50	15	19	11

C.1.3 Core scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	28.9	28.9	25.9
Peaker	4.7	2.7	1.7	1.3	1.2	1.4
Total	82.5	89.6	84.8	103.8	106.9	110.9

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	20%	33%	39%	44%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	10%
CCSCoal	0%	0%	0%	2%	1%	3%
CHP	7%	7%	8%	7%	8%	8%
Coal	32%	25%	22%	18%	11%	6%
CCGT	33%	35%	37%	28%	27%	23%
Peaker	6%	3%	2%	1%	1%	1%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

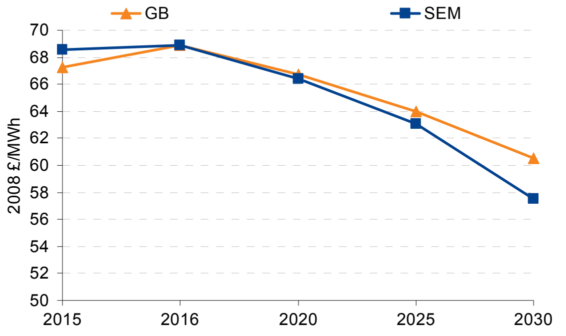
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

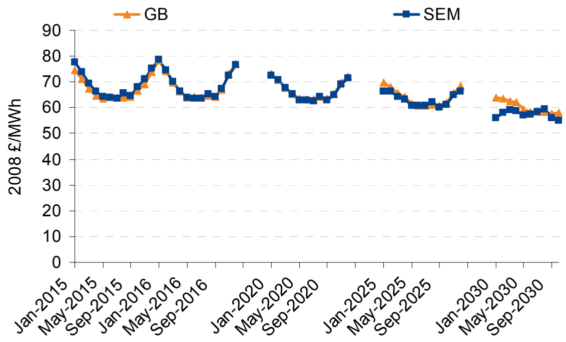
MW	2010	2015	2016	2020	2025	2030
GB	0	0	1122	0	242	1931
SEM	0	0	0	0	0	0

C.2 Capacity Payment scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2015	2016	2020	2025	2030
GB	67.3	68.9	66.8	64.0	60.5
SEM	68.6	68.9	66.4	63.1	57.5
	2015	2016	2020	2025	2030
€ per £	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	73.9	74.2	71.6	68.0	62.0

Monthly wholesale price

2008 £/MWh	2015	2016	2020	2025	2030
GB - Jan	74.7	78.2	73.0	69.8	64.0
GB - May	63.6	64.1	63.5	61.4	59.3
GB - Sep	64.1	64.3	63.6	60.7	57.8
SEM - Jan	74.7	78.2	73.0	69.8	64.0
SEM - May	63.6	64.1	63.5	61.4	59.3
SEM - Sep	64.1	64.3	63.6	60.7	57.8

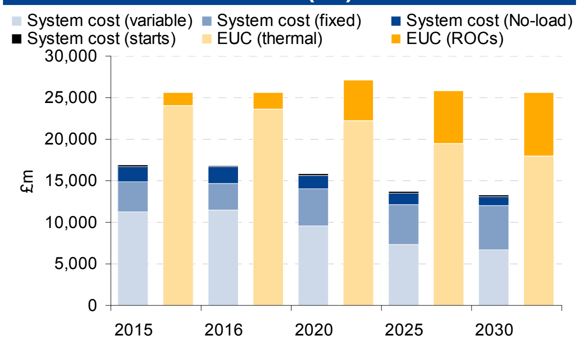
Internal Rate of Return (GB)

	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	11.2%	11.1%	10.9%
CCSCoal	N/A	N/A	5.9%	5.2%	4.8%
Coal	N/A	2.5%	1.7%	1.1%	0.9%
CCGT_F	7.0%	6.8%	5.5%	4.8%	4.6%
OCGT	7.9%	7.9%	7.8%	7.8%	8.1%

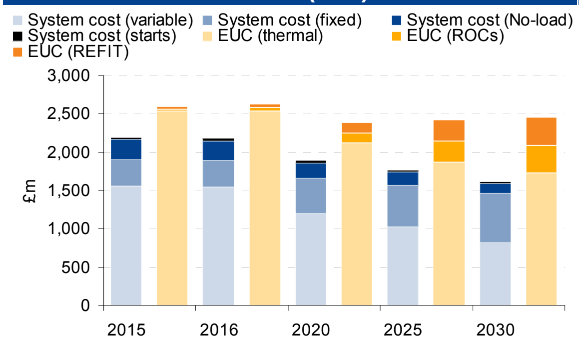
Internal rate of Return (SEM)

	2015	2016	2020	2025	2030
CCGT	4.9%	4.7%	3.7%	3.2%	3.1%
CCSCoal	N/A	N/A	N/A	N/A	4.4%
LMS100	1.1%	2.0%	4.5%	4.6%	4.9%
OCGT (Gasoil)	8.1%	8.1%	8.1%	8.0%	8.3%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

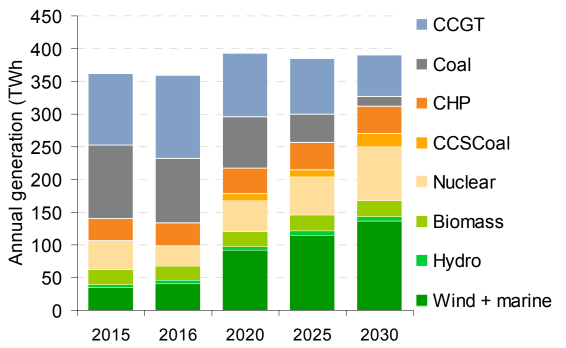
		2015	2016	2020	2025	2030
System cost	Variable	11302	11526	9539	7334	6672
	Fixed	3551	3173	4500	4841	5357
	No-Load	1856	1984	1642	1385	1056
	Starts	169	162	177	180	177
EUC	Thermal	24009	23654	22197	19461	17986
	ROCs	1599	1944	4910	6374	7655

End user cost vs annual cost (SEM)

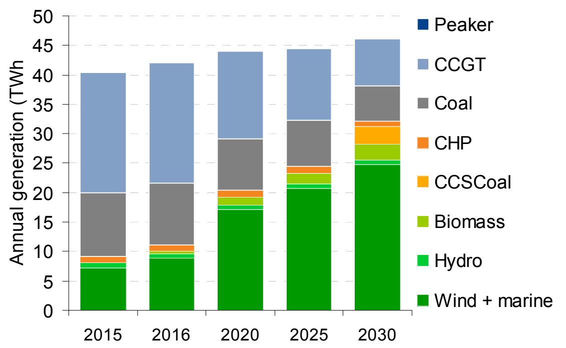
		2015	2016	2020	2025	2030
System cost	Variable	1560	1542	1195	1026	820
	Fixed	346	350	471	546	650
	No-Load	259	258	196	166	123
	Starts	24	27	26	26	24
EUC	Thermal	2533	2536	2119	1865	1733
	ROCs	31	45	134	278	360
	REFIT	63	79	180	253	314

C.2.1 Capacity Payment scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2015	2016	2020	2025	2030
Wind + marine	34.5	40.8	92.5	115.3	136.4
Hydro	4.9	4.9	5.3	6.0	6.7
Biomass	22.5	22.5	22.5	24.4	24.4
Nuclear	44.5	30.4	47.7	58.6	82.6
CCSCoal	0.0	0.0	10.5	10.3	19.6
CHP	34.0	34.9	38.6	42.8	42.2
Coal	112.9	99.0	78.3	42.2	15.6
CCGT	108.3	127.1	97.6	85.6	62.4
Peaker	0.0	0.0	0.0	0.0	0.0
Total	361.5	359.6	392.9	385.2	390.0

SEM annual generation

TWh	2015	2016	2020	2025	2030
Wind + marine	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	3.0
CHP	1.1	1.1	1.2	1.2	1.0
Coal	10.7	10.5	8.8	7.8	5.9
CCGT	20.5	20.3	14.8	12.2	8.0
Peaker	0.0	0.0	0.0	0.0	0.0
Total	40.4	42.0	44.0	44.5	46.1

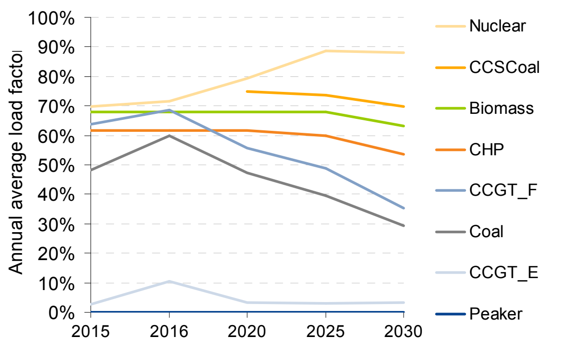
GB annual generation

% of total	2015	2016	2020	2025	2030
Wind + marine	9.5%	11.4%	23.5%	29.9%	35.0%
Hydro	1.4%	1.4%	1.4%	1.6%	1.7%
Biomass	6.2%	6.2%	5.7%	6.3%	6.3%
Nuclear	12.3%	8.4%	12.1%	15.2%	21.2%
CCSCoal	0.0%	0.0%	2.7%	2.7%	5.0%
CHP	9.4%	9.7%	9.8%	11.1%	10.8%
Coal	31.2%	27.5%	19.9%	10.9%	4.0%
CCGT	30.0%	35.4%	24.8%	22.2%	16.0%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	17.1%	19.0%	30.6%	37.8%	43.0%

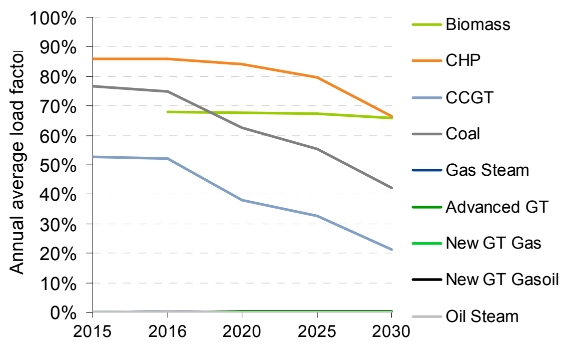
SEM annual generation

% of total	2015	2016	2020	2025	2030
Wind + marine	17.9%	21.0%	38.8%	46.5%	53.7%
Hydro	1.9%	1.9%	1.8%	1.7%	1.6%
Biomass	0.0%	1.1%	3.1%	4.2%	6.0%
CCSCoal	0.0%	0.0%	0.0%	0.0%	6.5%
CHP	2.8%	2.7%	2.7%	2.6%	2.1%
Coal	26.6%	25.0%	19.9%	17.5%	12.8%
CCGT	50.7%	48.4%	33.7%	27.5%	17.3%
Peaker	0.0%	0.1%	0.0%	0.0%	0.0%
RES %	19.9%	23.9%	43.7%	52.4%	61.2%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

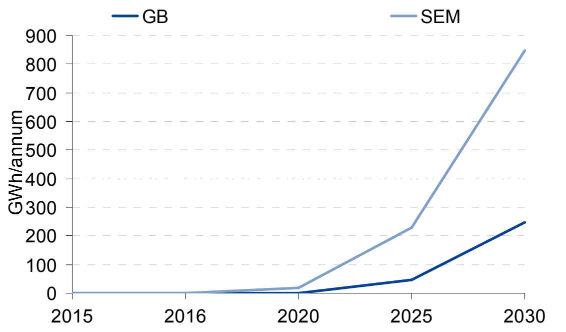
%	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	63%
Nuclear	70%	72%	79%	89%	88%
CCSCoal			75%	74%	70%
CHP	62%	62%	62%	60%	54%
CCGT_E	3%	11%	3%	3%	3%
CCGT_F	64%	69%	56%	49%	35%
Coal	48%	60%	47%	40%	29%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

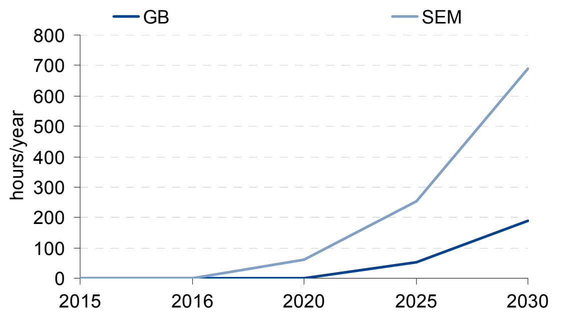
%	2015	2016	2020	2025	2030
Biomass		68%	68%	67%	66%
CCSCoal					78%
CHP	86%	86%	84%	79%	67%
Coal	77%	75%	63%	55%	42%
CCGT	53%	52%	38%	33%	21%
Gas Steam	0%	0%	0%	0%	0%
Advanced GT	<0.1%	<0.1%	0.2%	0.2%	0.3%
New GT Gas	<0.1%	0.1%	<0.1%	<0.1%	<0.1%
New GT Gasoil	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%
Oil Steam	<0.1%	0.3%	<0.1%	<0.1%	0.1%

C.2.2 Capacity Payment scenario page 3

Wind curtailment



Shedding periods



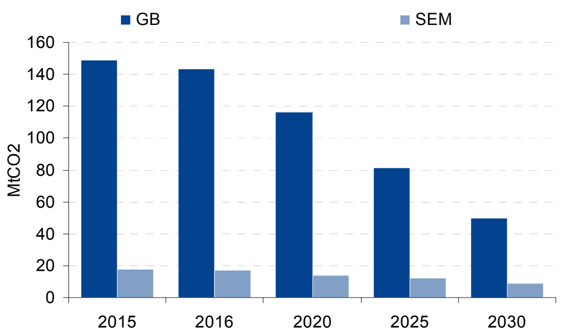
Wind curtailment

GWh/annum	2015	2016	2020	2025	2030
GB	0	0	0	45	247
SEM	0	0	20	230	846

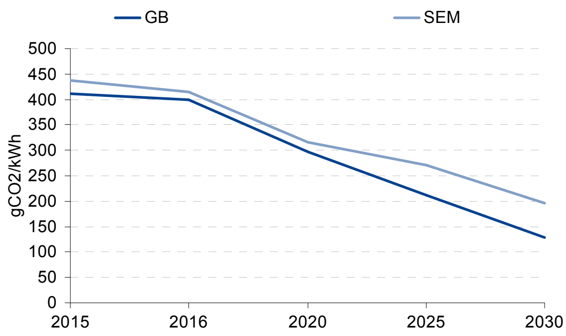
Shedding periods

hours/year	2015	2016	2020	2025	2030
GB	0	0	0	53	189
SEM	0	0	61	252	691

Carbon emissions



Carbon intensity



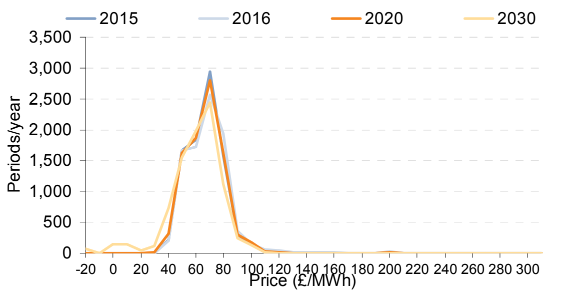
Carbon emissions

MtCO2	2015	2016	2020	2025	2030
GB	149	144	116	81	50
SEM	18	17	14	12	9

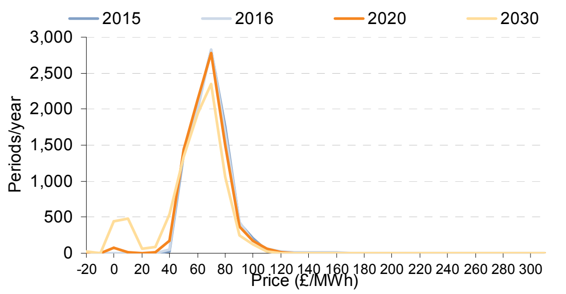
Carbon intensity

gCO2/kWh	2015	2016	2020	2025	2030
GB	411.2	399.2	296.1	211.4	128.4
SEM	438.0	415.1	315.6	270.5	195.6

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

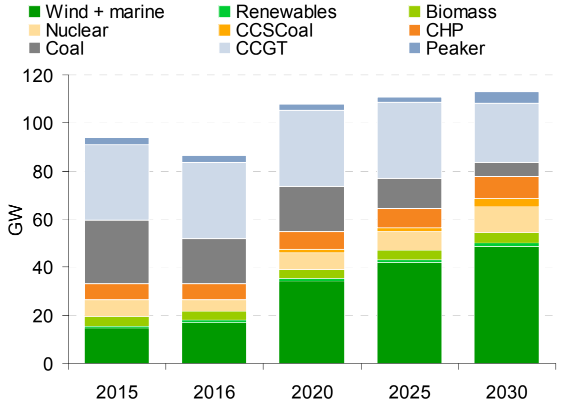
Periods/year	2015	2016	2020	2025	2030
<=0	0	0	5	82	217
0-20	0	0	3	41	190
20-50	1871	1855	1947	2118	2392
50-100	6816	6729	6745	6490	5920
100-200	68	160	58	27	35
>200	5	15	2	1	6

Price distribution (SEM)

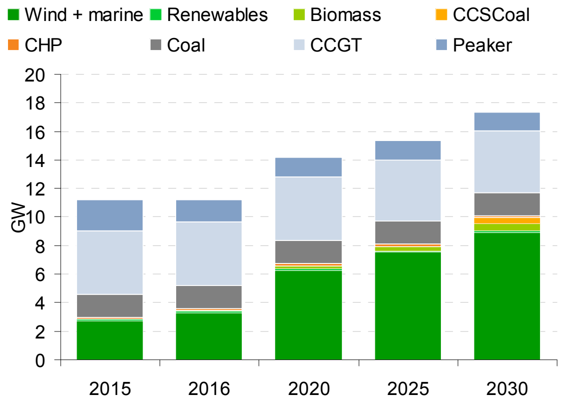
Periods/year	2015	2016	2020	2025	2030
<=0	0	0	75	244	471
0-20	0	0	15	116	541
20-50	1404	1505	1624	1752	1974
50-100	7268	7102	6972	6603	5721
100-200	84	141	72	45	47
>200	5	12	2	1	5

C.2.3 Capacity Payment scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2015	2016	2020	2025	2030
Wind + marine	14.5	16.8	34.1	41.8	48.7
Renewables	1.1	1.1	1.2	1.3	1.5
Biomass	3.8	3.8	3.8	4.1	4.4
Nuclear	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	1.6	1.6	3.2
CHP	6.3	6.5	7.2	8.2	9.0
Coal	26.8	18.9	18.9	12.2	6.1
CCGT	31.2	31.6	31.6	31.6	24.7
Peaker	2.9	3.0	2.6	2.5	4.7
Total	93.9	86.5	107.9	110.9	113.0

Installed capacity (SEM)

GW	2015	2016	2020	2025	2030
Wind + marine	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1
Biomass		0.1	0.2	0.3	0.5
CCSCoal					0.4
CHP	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6
CCGT	4.4	4.4	4.4	4.3	4.3
Peaker	2.2	1.6	1.4	1.4	1.3
Total	11.2	11.2	14.2	15.4	17.3

Installed capacity mix (SEM)

GW	2015	2016	2020	2025	2030
Wind + marine	15%	19%	32%	38%	43%
Renewables	1%	1%	1%	1%	1%
Biomass	4%	4%	3%	4%	4%
Nuclear	8%	6%	6%	7%	9%
CCSCoal	0%	0%	1%	1%	3%
CHP	7%	7%	7%	7%	8%
Coal	29%	22%	18%	11%	5%
CCGT	33%	37%	29%	29%	22%
Peaker	3%	3%	2%	2%	4%

Installed capacity mix (SEM)

GW	2015	2016	2020	2025	2030
Wind + marine	25%	29%	44%	49%	52%
Renewables	1%	1%	1%	1%	1%
Biomass	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	3%
CHP	1%	1%	1%	1%	1%
Coal	14%	14%	11%	10%	9%
CCGT	40%	40%	31%	28%	25%
Peaker	19%	14%	10%	9%	8%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	222
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	528	811	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5522	2306	4327	322		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

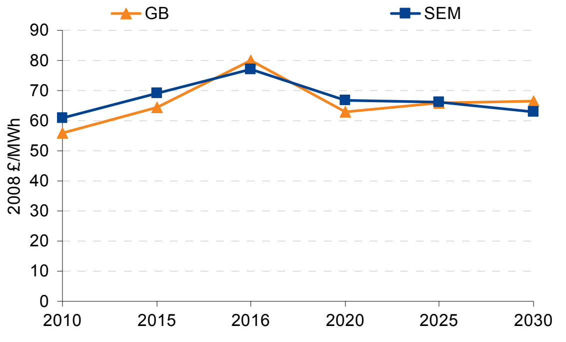
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	261	122	122	177	202	162
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	122	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

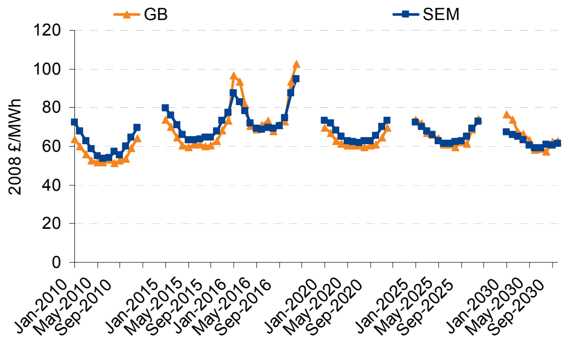
MW	2015	2016	2020	2025	2030
GB	0	78	0	0	127
SEM	0	0	0	0	0

C.3 Lower RES scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.8	64.5	80.1	63.0	65.9	66.5
SEM	60.9	69.2	77.1	66.7	66.1	62.9
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	66.3	74.5	83.0	71.8	71.3	67.8

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	63.6	73.8	96.7	69.6	73.9	76.4
GB - May	51.8	59.4	68.9	60.4	64.0	63.0
GB - Sep	52.8	60.6	70.9	60.3	62.5	62.2
SEM - Jan	63.6	73.8	96.7	69.6	73.9	76.4
SEM - May	51.8	59.4	68.9	60.4	64.0	63.0
SEM - Sep	52.8	60.6	70.9	60.3	62.5	62.2

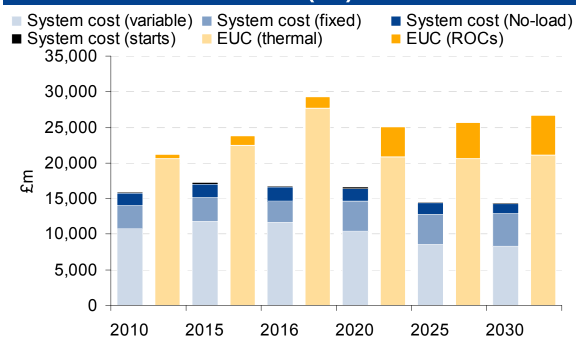
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.6%	12.2%	12.3%
CCSCoal	N/A	N/A	N/A	6.9%	7.0%	6.9%
Coal	N/A	N/A	4.4%	3.1%	3.8%	3.9%
CCGT_F	6.2%	9.1%	9.7%	6.5%	8.2%	8.8%
OCGT	<0	<0	<0	<0	<0	<0

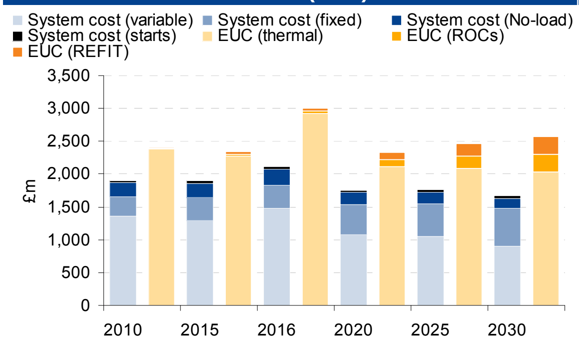
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	9.3%	9.2%	6.6%	6.0%	5.6%
CCSCoal	N/A	N/A	N/A	N/A	N/A	5.5%
LMS100	N/A	1.2%	2.1%	4.6%	4.6%	4.8%
OCGT (Gasoil)	8.8%	9.0%	9.1%	8.2%	8.1%	8.4%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

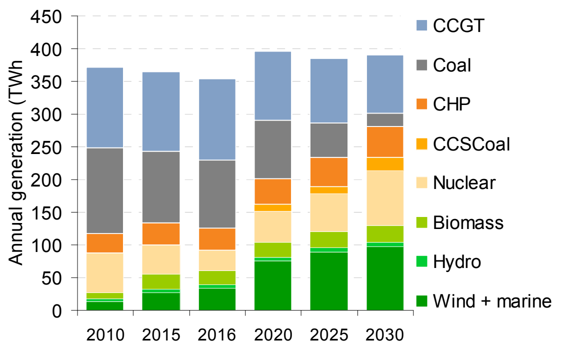
		2010	2015	2016	2020	2025	2030
System cost	Variable	10797	11802	11638	10480	8522	8304
	Fixed	3281	3287	3001	4155	4281	4609
	No-Load	1636	1969	1982	1772	1567	1364
	Starts	134	157	141	172	177	181
EUC	Thermal	20655	22478	27640	20906	20602	21122
	ROCs	532	1294	1637	4135	5102	5588

End user cost vs annual cost (SEM)

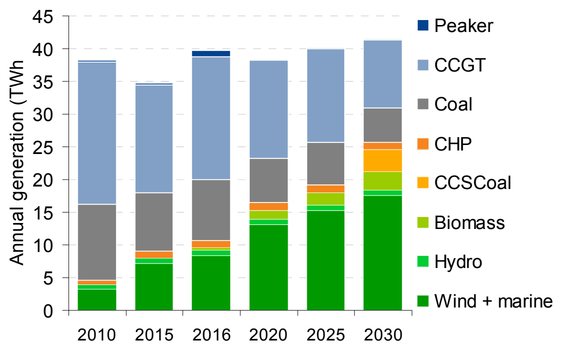
		2010	2015	2016	2020	2025	2030
System cost	Variable	1361	1296	1480	1083	1051	906
	Fixed	290	346	346	447	491	575
	No-Load	226	216	246	189	182	147
	Starts	22	34	46	32	36	35
EUC	Thermal	2385	2281	2916	2119	2089	2031
	ROCs	14	28	42	104	187	268
	REFIT	25	63	76	141	194	239

C.3.1 Low RES scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	27.5	33.6	76.3	89.8	97.1
Hydro	4.7	4.9	4.9	5.3	6.1	6.9
Biomass	9.9	22.5	22.5	22.5	24.4	26.0
Nuclear	60.2	44.5	30.4	47.7	58.7	83.7
CCSCoal	0.0	0.0	0.0	10.5	10.5	20.8
CHP	29.2	34.0	34.9	38.7	44.0	47.2
Coal	131.8	110.3	103.1	89.4	52.8	20.3
CCGT	123.0	121.0	124.6	105.2	98.3	88.4
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.7	364.7	354.0	395.7	384.6	390.4

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.2	8.3	13.2	15.3	17.6
Hydro	0.8	0.8	0.8	0.8	0.8	0.8
Biomass	0.0	0.0	0.5	1.4	1.9	2.9
CCSCoal	0.0	0.0	0.0	0.0	0.0	3.4
CHP	0.7	1.1	1.1	1.2	1.2	1.1
Coal	11.6	8.9	9.3	6.7	6.5	5.2
CCGT	21.7	16.5	18.8	15.1	14.4	10.5
Peaker	0.3	0.2	0.9	0.0	0.1	0.0
Total	38.2	34.7	39.7	38.3	40.1	41.4

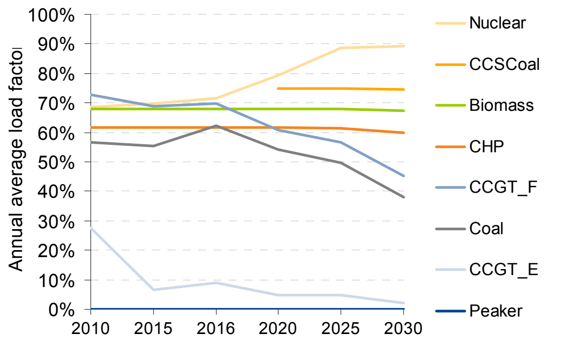
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	7.5%	9.5%	19.3%	23.3%	24.9%
Hydro	1.3%	1.3%	1.4%	1.3%	1.6%	1.8%
Biomass	2.7%	6.2%	6.3%	5.7%	6.3%	6.7%
Nuclear	16.2%	12.2%	8.6%	12.1%	15.3%	21.4%
CCSCoal	0.0%	0.0%	0.0%	2.7%	2.7%	5.3%
CHP	7.8%	9.3%	9.9%	9.8%	11.4%	12.1%
Coal	35.4%	30.3%	29.1%	22.6%	13.7%	5.2%
CCGT	33.1%	33.2%	35.2%	26.6%	25.6%	22.6%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	15.0%	17.2%	26.3%	31.3%	33.3%

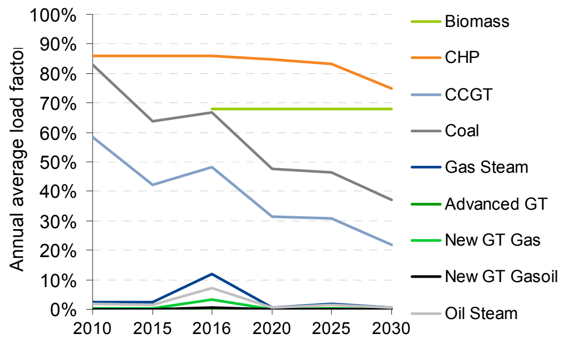
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.3%	20.7%	21.0%	34.4%	38.0%	42.4%
Hydro	2.1%	2.3%	2.0%	2.1%	2.0%	1.9%
Biomass	0.0%	0.0%	1.1%	3.6%	4.7%	6.9%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	8.2%
CHP	1.8%	3.3%	2.9%	3.2%	3.0%	2.6%
Coal	30.4%	25.7%	23.5%	17.4%	16.1%	12.5%
CCGT	56.7%	47.5%	47.3%	39.3%	35.9%	25.4%
Peaker	0.7%	0.6%	2.2%	0.1%	0.2%	0.1%
RES %	10.4%	23.0%	24.2%	40.0%	44.7%	51.2%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

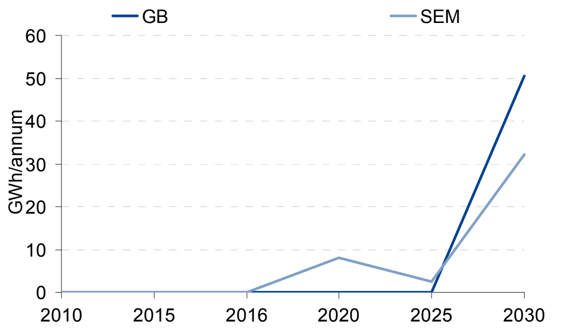
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	67%
Nuclear	68%	70%	72%	79%	89%	89%
CCSCoal				75%	75%	74%
CHP	62%	62%	62%	62%	61%	60%
CCGT_E	28%	7%	9%	5%	5%	2%
CCGT_F	73%	69%	70%	61%	57%	45%
Coal	57%	56%	62%	54%	50%	38%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

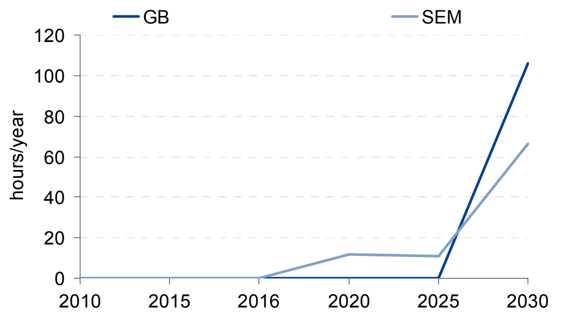
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	68%	68%
CCSCoal						88%
CHP	86%	86%	86%	85%	83%	75%
Coal	83%	64%	67%	48%	46%	37%
CCGT	58%	42%	48%	31%	31%	22%
Gas Steam	2%	2%	12%	1%	2%	1%
Advanced GT	<0.1%	<0.1%	<0.1%	0.1%	0.4%	0.1%
New GT Gas	0.2%	0.2%	3.2%	<0.1%	<0.1%	<0.1%
New GT Gasoil	<0.1%	<0.1%	0.6%	<0.1%	0.1%	<0.1%
Oil Steam	1.7%	1.4%	7.2%	0.7%	1.5%	0.5%

C.3.2 Low RES scenario page 3

Wind curtailment



Shedding periods



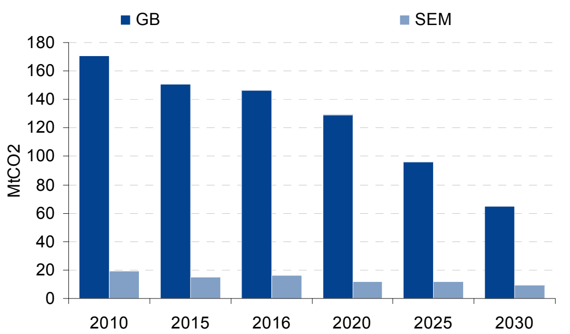
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	0	50
SEM	0	0	0	8	2	32

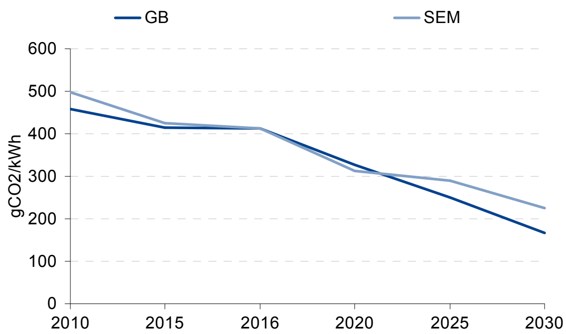
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	0	106
SEM	0	0	0	12	11	66

Carbon emissions



Carbon intensity



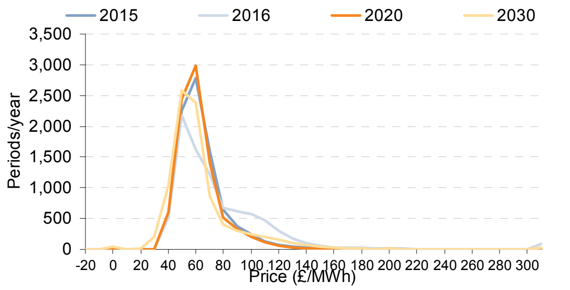
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	151	146	129	96	65
SEM	19	15	16	12	12	9

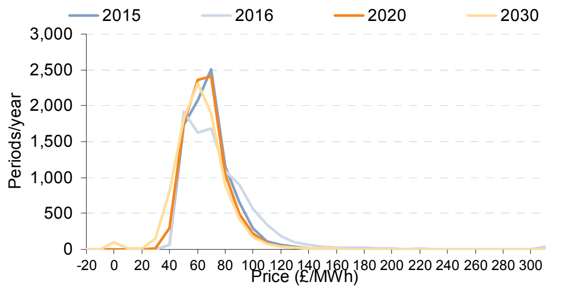
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.1	414.0	412.5	326.1	249.1	165.7
SEM	497.0	425.5	413.4	312.6	289.9	224.6

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

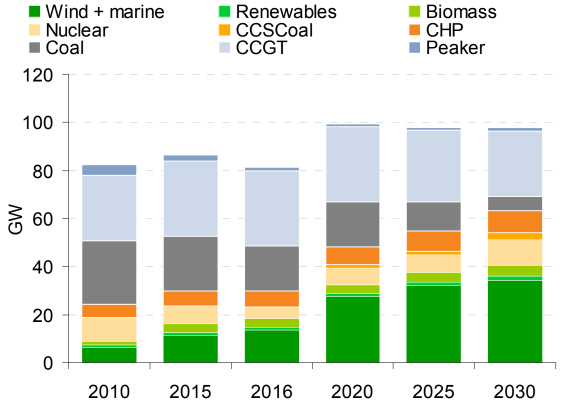
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	0	7	39
0-20	0	0	0	1	5	16
20-50	5109	2806	2688	3041	3157	3812
50-100	3534	5637	4699	5448	4993	4191
100-200	112	305	1235	259	563	641
>200	5	12	138	11	36	61

Price distribution (SEM)

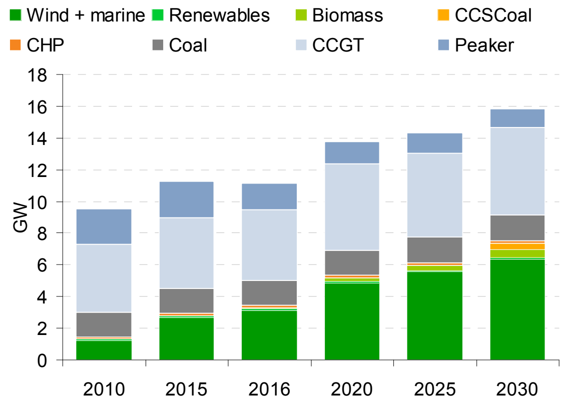
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	0	16	101
0-20	0	0	0	0	5	22
20-50	3543	1794	1991	2061	2224	2752
50-100	5095	6691	5881	6517	6251	5705
100-200	117	267	828	170	249	171
>200	5	8	59	12	15	10

C.3.3 Low RES scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	11.4	13.5	27.6	32.0	34.4
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	31.1	29.8	27.1
Peaker	4.7	2.7	1.7	1.3	1.2	1.6
Total	**82.5**	**86.5**	**81.5**	**99.5**	**98.0**	**98.0**

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.1	4.8	5.5	6.4
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	5.5	5.3	5.5
Peaker	2.3	2.3	1.7	1.4	1.3	1.2
Total	**9.6**	**11.3**	**11.2**	**13.8**	**14.3**	**15.8**

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	13%	17%	28%	33%	35%
Renewables	1%	1%	1%	1%	1%	2%
Biomass	2%	4%	5%	4%	4%	4%
Nuclear	12%	8%	6%	7%	8%	11%
CCSCoal	0%	0%	0%	2%	2%	3%
CHP	7%	7%	8%	7%	8%	9%
Coal	32%	26%	23%	19%	12%	6%
CCGT	33%	36%	38%	31%	30%	28%
Peaker	6%	3%	2%	1%	1%	2%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	28%	35%	39%	40%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	3%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	12%	11%	10%
CCGT	44%	40%	40%	40%	37%	35%
Peaker	24%	20%	15%	10%	9%	8%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2179	3154	2179	3154
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Thermal	391	122	122	1666	3858	5362
Renewable	2179	4573	8087	8087	8087	8087
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
Thermal	122	122	3858	122	3858	660
Renewable	2553	2553	2553	2553	2553	1569
	2027	**2028**	**2029**	**2030**		
Thermal	5442	2324	4556	740		
Renewable	1569	1569	1569	1569		

Investment cost (SEM)

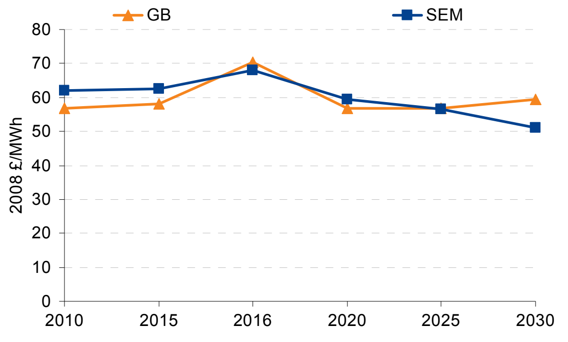
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	511	1486	511	1486
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Thermal	301	122	122	316	455	440
Renewable	511	546	641	641	641	641
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
Thermal	122	122	122	122	122	1107
Renewable	471	471	471	471	471	530
	2027	**2028**	**2029**	**2030**		
Thermal	122	122	122	122		
Renewable	530	530	530	530		

Lost Load

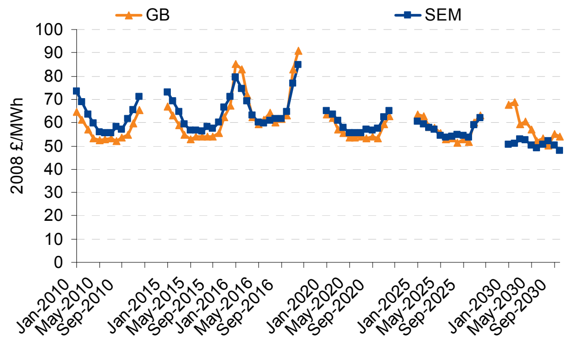
MW	2010	2015	2016	2020	2025	2030
GB	0	0	1370	0	100	1153
SEM	0	0	0	0	0	0

C.4 Carbon Drop scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	56.7	58.1	70.4	56.8	56.8	59.4
SEM	62.1	62.4	68.0	59.3	56.6	51.0
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	67.6	67.3	73.3	63.9	61.0	54.9

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	64.8	67.1	85.0	63.5	63.5	67.5
GB - May	52.5	52.8	59.4	53.7	55.4	57.1
GB - Sep	53.8	54.2	61.5	53.9	52.8	55.1
SEM - Jan	64.8	67.1	85.0	63.5	63.5	67.5
SEM - May	52.5	52.8	59.4	53.7	55.4	57.1
SEM - Sep	53.8	54.2	61.5	53.9	52.8	55.1

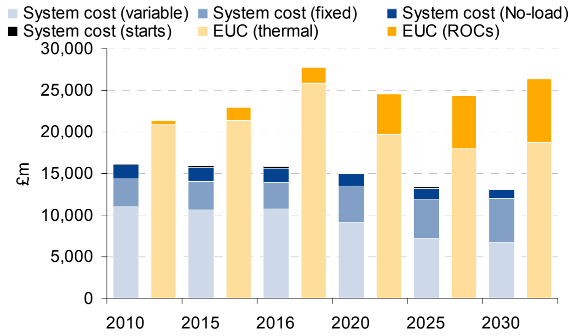
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	9.9%	10.4%	10.6%
CCSCoal	N/A	N/A	N/A	4.8%	5.0%	5.1%
Coal	N/A	N/A	6.8%	5.8%	6.5%	7.0%
CCGT_F	4.5%	7.3%	7.7%	5.9%	7.9%	9.4%
OCGT	<0	<0	<0	<0	<0	<0

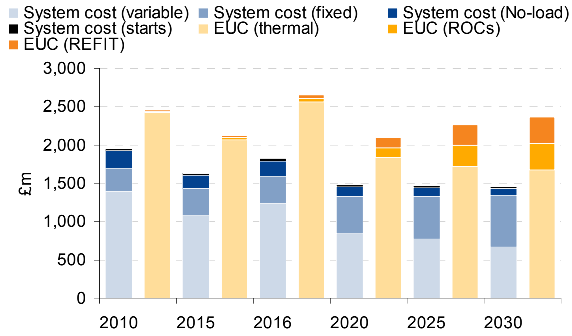
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	7.2%	7.2%	5.9%	5.4%	5.3%
CCSCoal	N/A	N/A	N/A	N/A	N/A	1.9%
LMS100	N/A	2.8%	3.7%	6.7%	6.8%	6.9%
OCGT (Gasoil)	8.9%	9.2%	9.4%	8.7%	8.7%	9.0%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

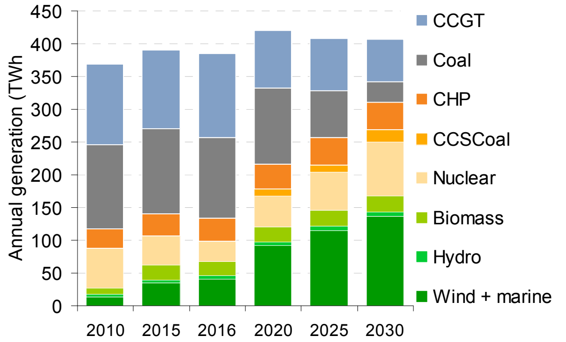
		2010	2015	2016	2020	2025	2030
System cost	Variable	11072	10614	10757	9145	7212	6710
	Fixed	3281	3414	3129	4390	4730	5317
	No-Load	1673	1741	1799	1467	1273	1019
	Starts	139	155	148	148	158	165
EUC	Thermal	20827	21336	25846	19629	18016	18702
	ROCs	532	1599	1944	4910	6374	7655

End user cost vs annual cost (SEM)

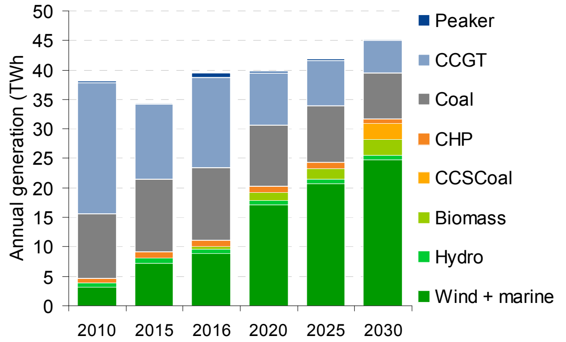
		2010	2015	2016	2020	2025	2030
System cost	Variable	1401	1086	1239	847	769	674
	Fixed	290	348	352	481	558	662
	No-Load	235	166	193	127	113	95
	Starts	22	30	41	27	26	25
EUC	Thermal	2425	2066	2565	1832	1715	1668
	ROCs	14	31	45	134	276	351
	REFIT	25	63	79	180	253	312

C.4.1 Carbon Drop scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.0	6.8
Biomass	9.9	22.5	22.5	22.5	24.4	23.7
Nuclear	60.2	44.5	30.4	47.7	58.6	82.8
CCSCoal	0.0	0.0	0.0	10.5	10.3	19.6
CHP	29.2	34.0	34.9	37.8	41.7	41.8
Coal	129.2	130.3	122.6	116.7	71.4	31.5
CCGT	122.6	119.8	129.2	87.1	80.0	64.5
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	368.8	390.4	385.3	420.1	407.7	407.0

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.7
CHP	0.7	1.1	1.1	1.0	1.0	0.8
Coal	11.0	12.3	12.2	10.4	9.6	7.7
CCGT	22.2	12.7	15.4	8.9	7.8	5.6
Peaker	0.3	0.2	0.8	0.2	0.2	0.1
Total	38.2	34.4	39.6	39.7	41.9	45.2

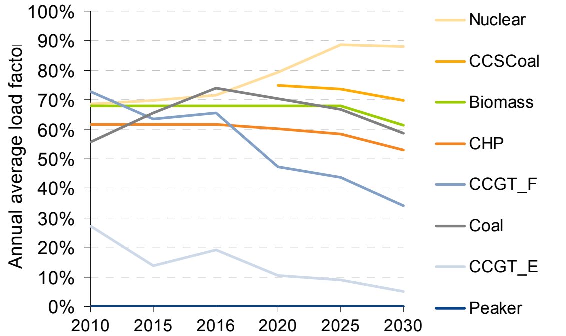
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	8.8%	10.6%	22.0%	28.3%	33.5%
Hydro	1.3%	1.3%	1.3%	1.3%	1.5%	1.7%
Biomass	2.7%	5.8%	5.8%	5.3%	6.0%	5.8%
Nuclear	16.3%	11.4%	7.9%	11.4%	14.4%	20.3%
CCSCoal	0.0%	0.0%	0.0%	2.5%	2.5%	4.8%
CHP	7.9%	8.7%	9.1%	9.0%	10.2%	10.3%
Coal	35.0%	33.4%	31.8%	27.8%	17.5%	7.7%
CCGT	33.2%	30.7%	33.5%	20.7%	19.6%	15.8%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.5%	15.8%	17.7%	28.6%	35.7%	41.0%

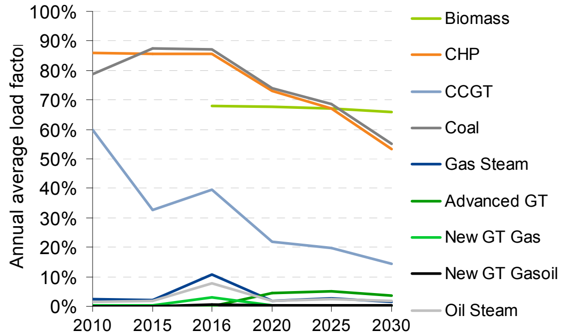
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.4%	21.1%	22.3%	42.9%	49.4%	54.7%
Hydro	2.1%	2.3%	2.0%	2.0%	1.8%	1.6%
Biomass	0.0%	0.0%	1.1%	3.4%	4.5%	6.1%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%
CHP	1.8%	3.3%	2.9%	2.6%	2.3%	1.7%
Coal	28.9%	35.7%	30.9%	26.1%	22.9%	17.1%
CCGT	58.2%	37.1%	38.9%	22.5%	18.5%	12.5%
Peaker	0.7%	0.6%	2.0%	0.5%	0.5%	0.3%
RES %	10.4%	23.4%	25.4%	48.4%	55.7%	62.4%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

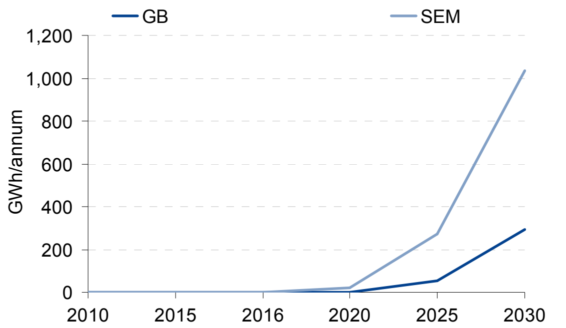
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	61%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	60%	58%	53%
CCGT_E	27%	14%	19%	10%	9%	5%
CCGT_F	73%	64%	66%	47%	44%	34%
Coal	56%	65%	74%	70%	67%	59%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

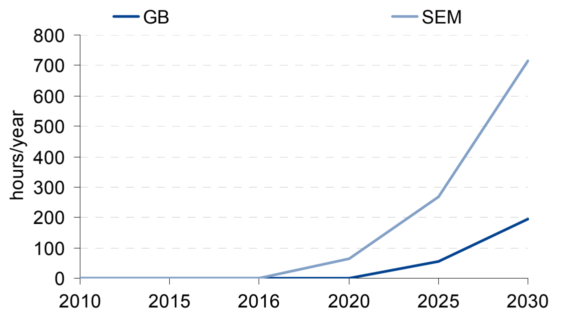
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						70%
CHP	86%	86%	86%	73%	67%	53%
Coal	79%	88%	87%	74%	69%	55%
CCGT	60%	33%	39%	22%	20%	14%
Gas Steam	3%	2%	11%	2%	3%	2%
Advanced GT	<0.1%	<0.1%	<0.1%	4.5%	5.0%	3.7%
New GT Gas	0.2%	0.2%	3.0%	0.3%	0.2%	0.1%
New GT Gasoil	<0.1%	<0.1%	0.6%	0.2%	0.3%	0.3%
Oil Steam	1.5%	1.7%	7.7%	1.9%	2.3%	1.7%

C.4.2 Carbon Drop scenario page 3

Wind curtailment



Shedding periods



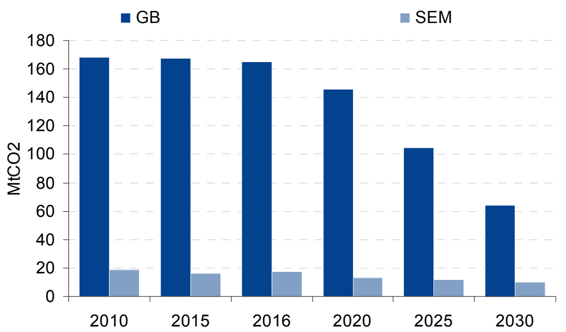
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	292
SEM	0	0	0	22	271	1034

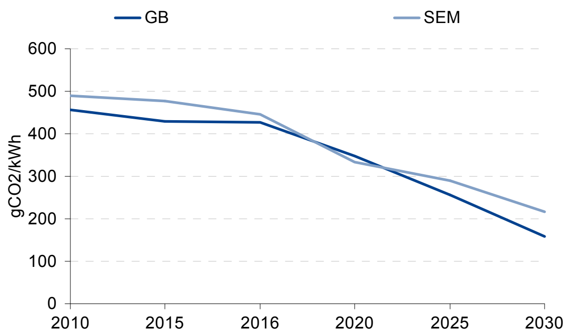
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	195
SEM	0	0	0	63	269	716

Carbon emissions



Carbon intensity



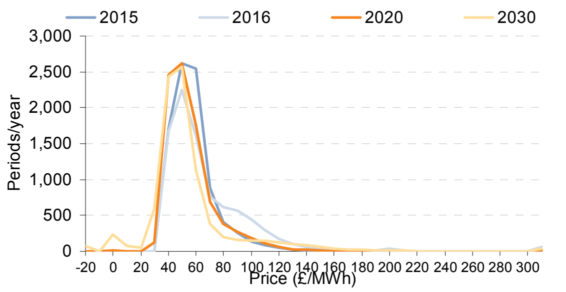
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	168	168	165	146	105	64
SEM	19	16	18	13	12	10

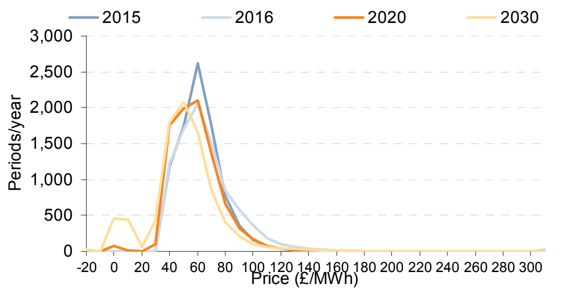
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	456.4	429.8	427.6	347.1	256.8	157.8
SEM	489.3	476.1	446.4	333.4	289.8	217.2

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

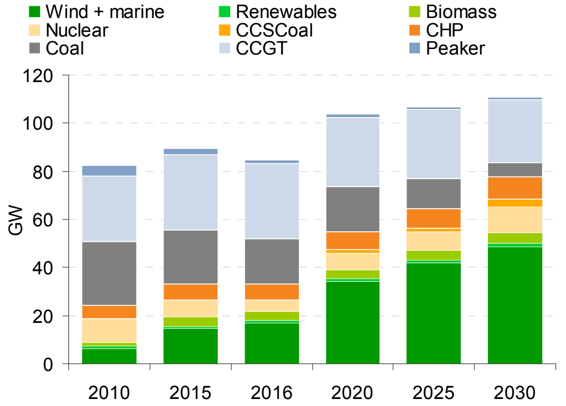
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	10	108	307
0-20	0	0	0	5	36	127
20-50	4878	4332	3933	5190	5361	5587
50-100	3760	4234	4004	3287	2850	2016
100-200	115	189	726	250	377	651
>200	7	5	98	17	28	72

Price distribution (SEM)

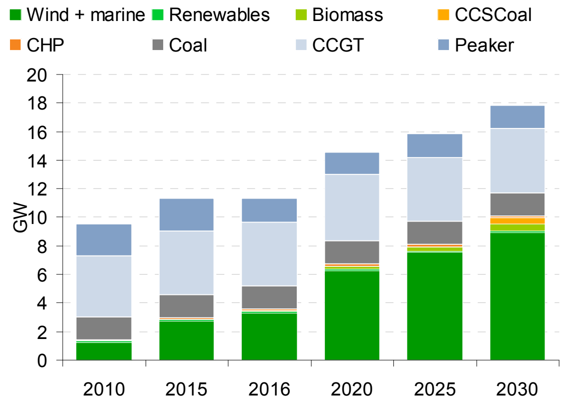
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	78	256	489
0-20	0	0	0	16	117	514
20-50	3214	2926	2920	3845	4092	4303
50-100	5418	5676	5358	4637	4063	3233
100-200	120	150	441	171	215	214
>200	8	8	41	14	17	8

C.4.3 Carbon Drop scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	28.9	28.9	25.9
Peaker	4.7	2.7	1.7	1.3	1.2	1.4
Total	82.5	89.6	84.8	103.8	106.9	110.9

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	20%	33%	39%	44%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	10%
CCSCoal	0%	0%	0%	2%	1%	3%
CHP	7%	7%	8%	7%	8%	8%
Coal	32%	25%	22%	18%	11%	6%
CCGT	33%	35%	37%	28%	27%	23%
Peaker	6%	3%	2%	1%	1%	1%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

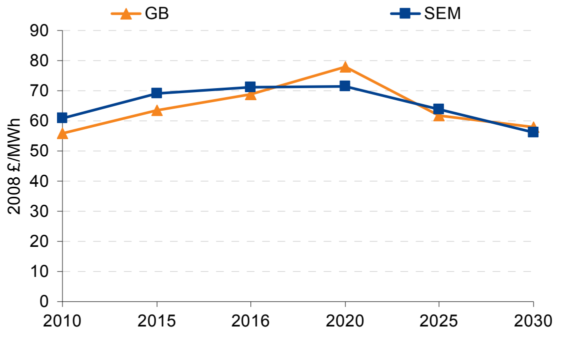
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

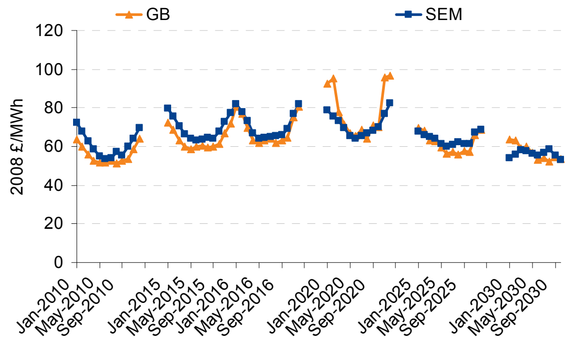
MW	2010	2015	2016	2020	2025	2030
GB	0	0	1122	0	242	1931
SEM	0	0	0	0	0	0

C.5 IED scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.8	63.6	68.7	77.8	61.8	57.9
SEM	60.9	69.1	71.1	71.4	63.7	56.3
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	66.3	74.4	76.6	77.0	68.7	60.6

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	63.6	72.4	80.6	92.6	69.7	63.7
GB - May	51.7	58.8	61.8	66.7	59.6	56.8
GB - Sep	52.5	60.0	63.4	70.8	57.9	54.7
SEM - Jan	63.6	72.4	80.6	92.6	69.7	63.7
SEM - May	51.7	58.8	61.8	66.7	59.6	56.8
SEM - Sep	52.5	60.0	63.4	70.8	57.9	54.7

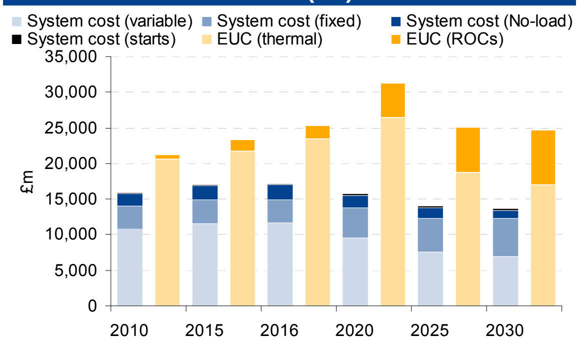
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.5%	10.4%	10.2%
CCSCoal	N/A	N/A	N/A	6.3%	4.3%	3.8%
Coal	N/A	N/A	4.0%	2.0%	-0.8%	#####
CCGT_F	6.7%	9.8%	10.6%	7.2%	1.1%	0.7%
OCGT	<0	<0	<0	<0	<0	<0

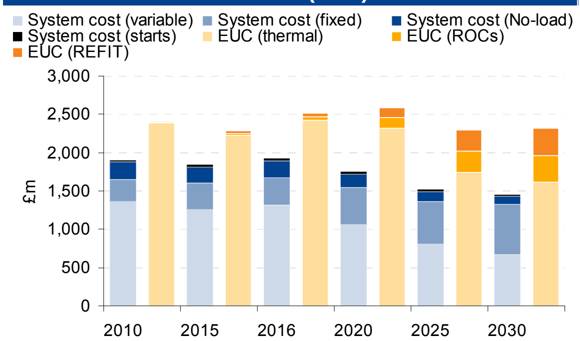
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	8.9%	8.9%	8.3%	5.8%	5.3%
CCSCoal	N/A	N/A	N/A	N/A	N/A	3.9%
LMS100	N/A	4.1%	5.2%	8.0%	6.1%	6.0%
OCGT (Gasoil)	9.2%	9.6%	9.8%	9.4%	8.4%	8.6%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

		2010	2015	2016	2020	2025	2030
System cost	Variable	10798	11530	11710	9523	7581	6918
	Fixed	3281	3414	3200	4239	4739	5393
	No-Load	1636	1925	2043	1808	1512	1146
	Starts	134	158	151	175	184	185
EUC	Thermal	20649	21756	23433	26411	18695	17045
	ROCs	532	1599	1944	4910	6374	7655

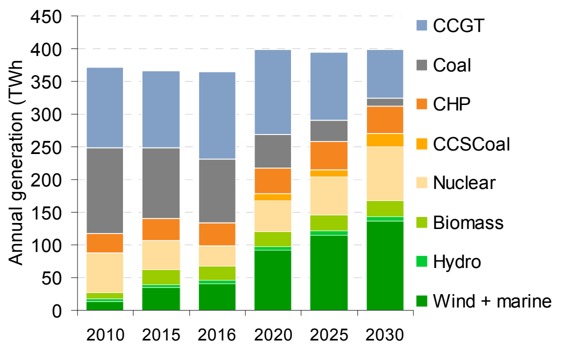
End user cost vs annual cost (SEM)

		2010	2015	2016	2020	2025	2030
System cost	Variable	1361	1258	1317	1059	806	666
	Fixed	290	348	352	481	558	662
	No-Load	226	209	218	174	130	99
	Starts	22	32	39	39	30	26
EUC	Thermal	2385	2222	2423	2322	1742	1616
	ROCs	14	31	45	134	276	351
	REFIT	25	63	79	180	253	312

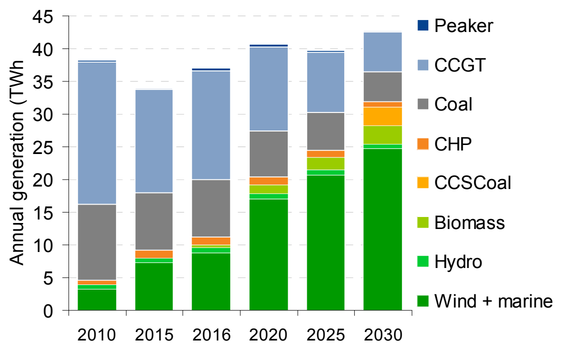
In the IED, since new entry is not needed in 2030 and as capacity margins are reasonable, we have assumed that CCGT profitability trends to new entry levels by 2035. For other technology except OCGTs we have assumed the same absolute change in revenues. For OCGTs this may not be the case – without running beyond 2030, it is impossible to be certain OCGT revenues actually do stay below zero.

C.5.1 IED scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.0	6.8
Biomass	9.9	22.5	22.5	22.5	24.4	24.5
Nuclear	60.2	44.5	30.4	47.7	58.6	82.8
CCSCoal	0.0	0.0	0.0	10.5	10.3	19.6
CHP	29.2	34.0	34.9	38.6	42.8	42.3
Coal	131.8	108.5	97.4	51.9	33.6	11.9
CCGT	123.0	117.3	134.4	129.1	103.9	74.0
Peaker	0.0	0.0	0.0	0.1	0.0	0.0
Total	371.8	366.1	365.3	398.1	394.9	398.3

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.8
CHP	0.7	1.1	1.1	1.2	1.1	0.8
Coal	11.6	8.8	8.8	7.1	5.9	4.6
CCGT	21.7	15.8	16.6	12.8	9.2	6.0
Peaker	0.3	0.2	0.4	0.5	0.2	0.1
Total	38.2	34.0	37.0	40.7	39.7	42.6

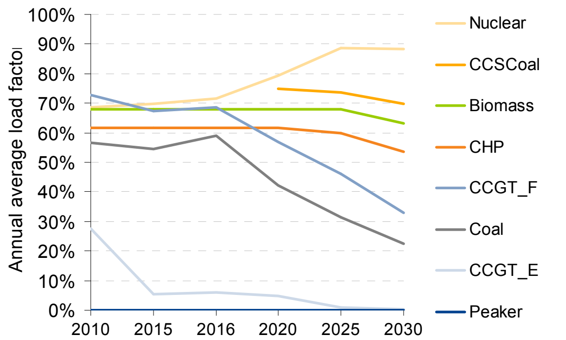
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	9.4%	11.2%	23.2%	29.2%	34.3%
Hydro	1.3%	1.3%	1.3%	1.3%	1.5%	1.7%
Biomass	2.7%	6.1%	6.1%	5.6%	6.2%	6.1%
Nuclear	16.2%	12.1%	8.3%	12.0%	14.9%	20.8%
CCSCoal	0.0%	0.0%	0.0%	2.6%	2.6%	4.9%
CHP	7.8%	9.3%	9.6%	9.7%	10.8%	10.6%
Coal	35.4%	29.6%	26.7%	13.0%	8.5%	3.0%
CCGT	33.1%	32.0%	36.8%	32.4%	26.3%	18.6%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	16.9%	18.7%	30.2%	36.9%	42.1%

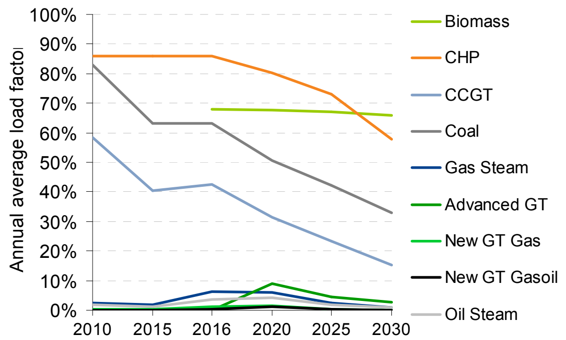
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.3%	21.4%	23.8%	41.9%	52.1%	58.0%
Hydro	2.1%	2.3%	2.1%	1.9%	1.9%	1.7%
Biomass	0.0%	0.0%	1.2%	3.4%	4.7%	6.5%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	6.7%
CHP	1.8%	3.3%	3.1%	2.8%	2.7%	2.0%
Coal	30.4%	26.0%	23.9%	17.4%	14.9%	10.8%
CCGT	56.7%	46.5%	44.8%	31.4%	23.1%	14.2%
Peaker	0.7%	0.5%	1.2%	1.2%	0.5%	0.2%
RES %	10.4%	23.7%	27.2%	47.2%	58.8%	66.2%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

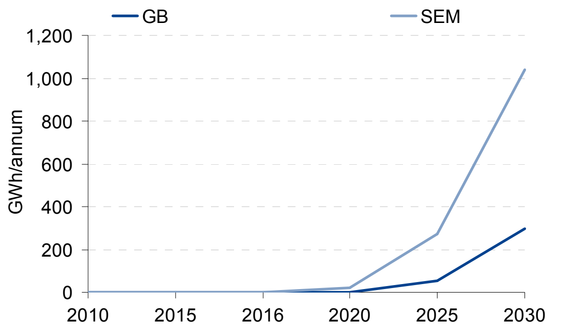
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	63%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	28%	5%	6%	5%	1%	0%
CCGT_F	73%	67%	69%	57%	46%	33%
Coal	57%	55%	59%	42%	32%	22%
Peaker	<0.1%	<0.1%	<0.1%	0.11%	<0.1%	<0.1%

SEM annual average load factor

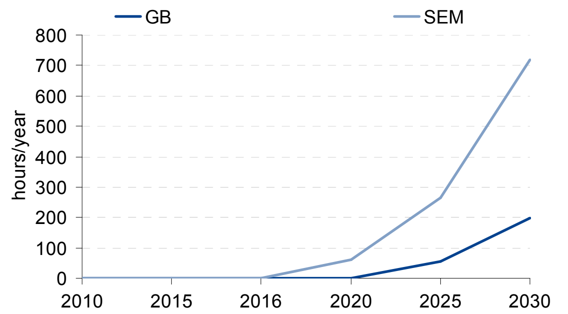
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						74%
CHP	86%	86%	86%	80%	73%	58%
Coal	83%	63%	63%	51%	42%	33%
CCGT	58%	41%	42%	31%	23%	15%
Gas Steam	2%	2%	6%	6%	2%	1%
Advanced GT	<0.1%	<0.1%	<0.1%	9.1%	4.6%	2.7%
New GT Gas	0.2%	0.2%	1.2%	1.4%	0.2%	<0.1%
New GT Gasoil	<0.1%	<0.1%	0.3%	1.1%	0.3%	0.1%
Oil Steam	1.7%	1.1%	3.7%	4.2%	1.9%	0.8%

C.5.2 IED scenario page 3

Wind curtailment



Shedding periods



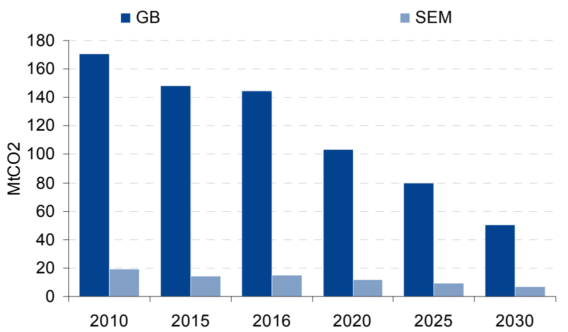
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	298
SEM	0	0	0	21	272	1041

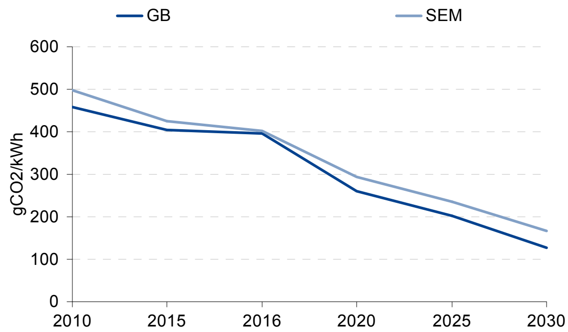
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	57	198
SEM	0	0	0	60	265	719

Carbon emissions



Carbon intensity



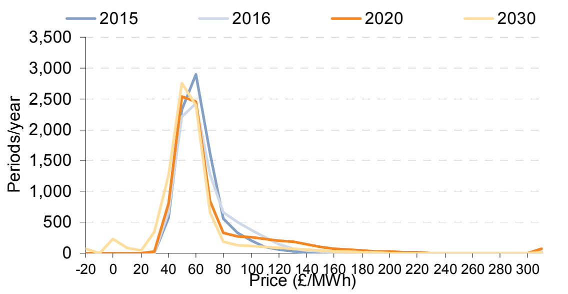
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	148	144	104	80	51
SEM	19	14	15	12	9	7

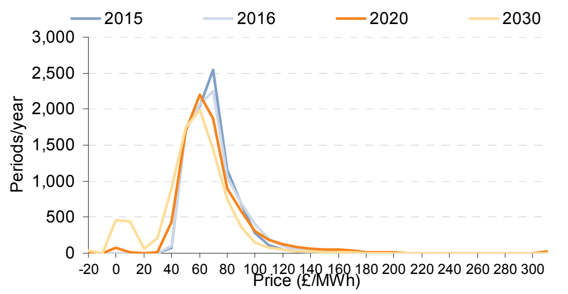
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.1	404.2	395.0	260.4	201.6	126.8
SEM	497.0	424.2	401.8	293.6	235.7	167.2

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

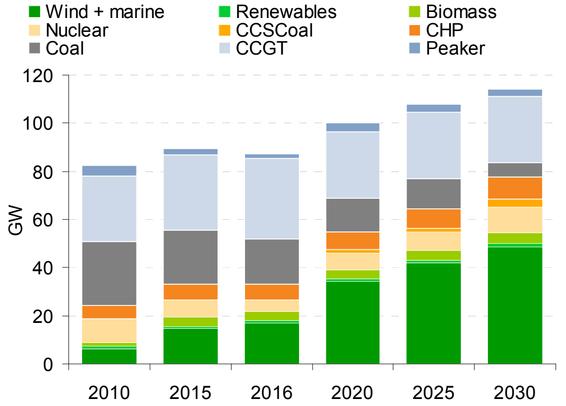
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	6	101	305
0-20	0	0	0	4	26	122
20-50	5111	2896	2876	3369	3834	4360
50-100	3533	5601	5249	4172	4295	3495
100-200	111	254	588	1084	475	444
>200	5	9	48	127	29	35

Price distribution (SEM)

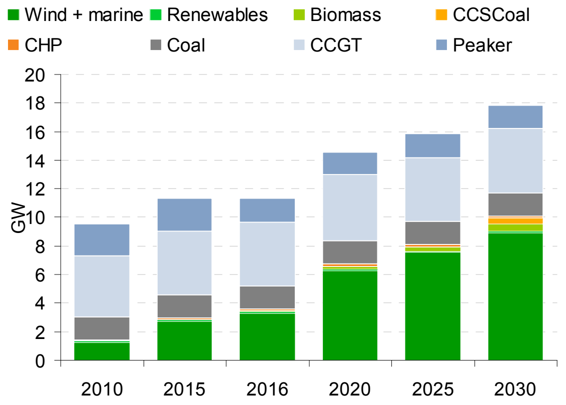
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	74	249	487
0-20	0	0	0	15	109	510
20-50	3540	1807	1837	2148	2431	2849
50-100	5101	6695	6467	5857	5631	4686
100-200	114	249	428	625	322	220
>200	5	9	28	43	18	9

C.5.3 IED scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	14.1	12.2	6.1
CCGT	27.0	31.2	33.7	27.6	27.6	27.6
Peaker	4.7	2.7	1.7	3.7	3.6	2.8
Total	82.5	89.6	87.2	100.1	108.0	114.0

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	19%	34%	39%	43%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	9%
CCSCoal	0%	0%	0%	2%	1%	3%
CHP	7%	7%	7%	7%	8%	8%
Coal	32%	25%	22%	14%	11%	5%
CCGT	33%	35%	39%	28%	26%	24%
Peaker	6%	3%	2%	4%	3%	2%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	1768	122	1626	5064	8381
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5362	1626	3858	122		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

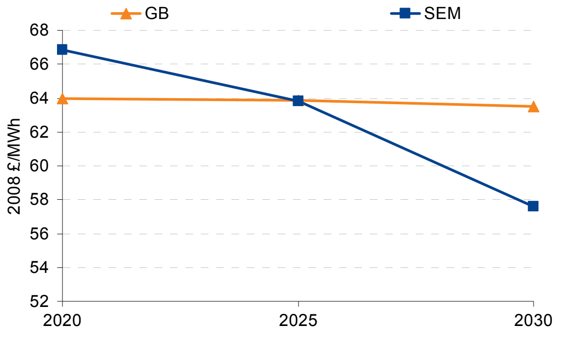
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

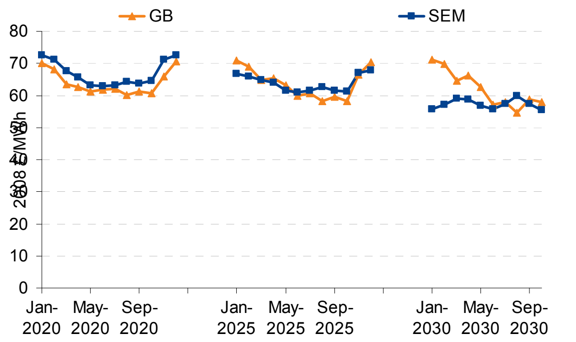
MW	2010	2015	2016	2020	2025	2030
GB	0	0	34	4516	115	121
SEM	0	0	0	13	0	0

C.6 Offshore Growth scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2020	2025	2030
GB	64.0	63.9	63.5
SEM	66.9	63.8	57.6
	2020	2025	2030
€ per £	1.08	1.08	1.08
SEM (2008 €/MWh)	72.1	68.8	62.1

Monthly wholesale price

2008 £/MWh	2020	2025	2030
GB - Jan	70.1	71.0	71.2
GB - May	61.4	63.3	62.5
GB - Sep	61.3	59.7	58.7
SEM - Jan	70.1	71.0	71.2
SEM - May	61.4	63.3	62.5
SEM - Sep	61.3	59.7	58.7

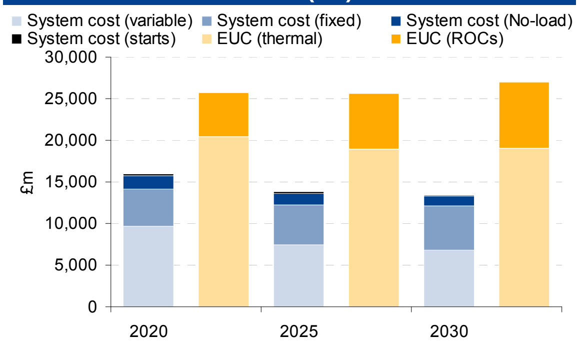
Internal Rate of Return (GB)

	2020	2025	2030
Nuclear	11.3%	11.6%	11.6%
CCSCoal	6.5%	6.4%	6.3%
Coal	2.8%	3.3%	3.6%
CCGT_F	6.5%	8.0%	8.9%
OCGT	<0	<0	<0

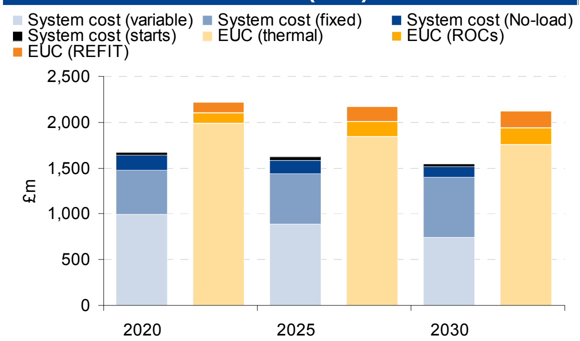
Internal rate of Return (SEM)

	2020	2025	2030
CCGT	7.4%	6.9%	6.6%
CCSCoal	N/A	N/A	4.7%
LMS100	6.7%	6.7%	6.7%
OCGT (Gasoil)	8.7%	8.6%	8.9%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

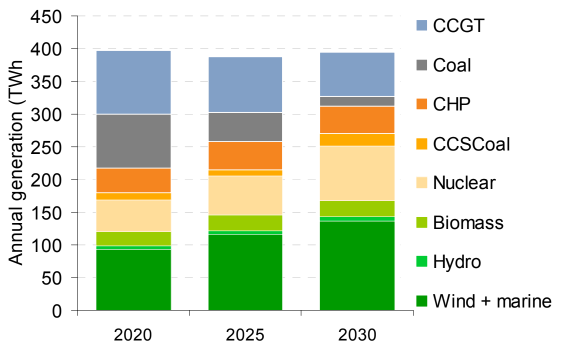
		2020	2025	2030
System cost	Variable	9716	7469	6815
	Fixed	4412	4746	5348
	No-Load	1655	1396	1096
	Starts	179	182	184
EUC	Thermal	20479	18922	19039
	ROCs	5242	6717	7996

End user cost vs annual cost (SEM)

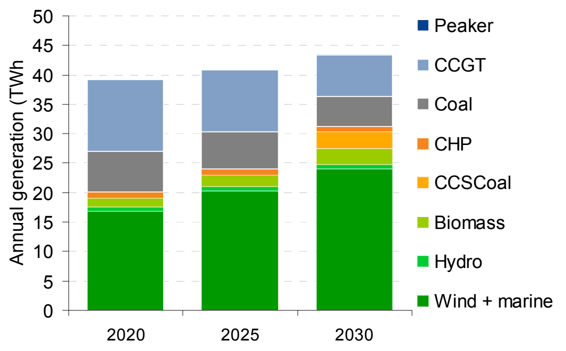
		2020	2025	2030
System cost	Variable	991	887	742
	Fixed	482	555	658
	No-Load	163	144	112
	Starts	32	31	30
EUC	Thermal	1989	1847	1759
	ROCs	118	164	182
	REFIT	171	224	264

C.6.1 Offshore Growth scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2020	2025	2030
Wind + marine	93.1	115.7	137.1
Hydro	5.3	6.0	6.8
Biomass	22.5	24.3	24.4
Nuclear	47.7	58.6	82.7
CCSCoal	10.5	10.3	19.5
CHP	38.6	42.7	41.9
Coal	81.9	44.6	14.7
CCGT	97.1	85.7	67.5
Peaker	0.0	0.0	0.0
Total	396.6	388.0	394.6

SEM annual generation

TWh	2020	2025	2030
Wind + marine	16.9	20.3	24.0
Hydro	0.8	0.8	0.7
Biomass	1.4	1.9	2.8
CCSCoal	0.0	0.0	2.8
CHP	1.1	1.1	0.9
Coal	6.9	6.4	5.1
CCGT	12.1	10.4	7.1
Peaker	0.2	0.2	0.1
Total	39.3	41.0	43.5

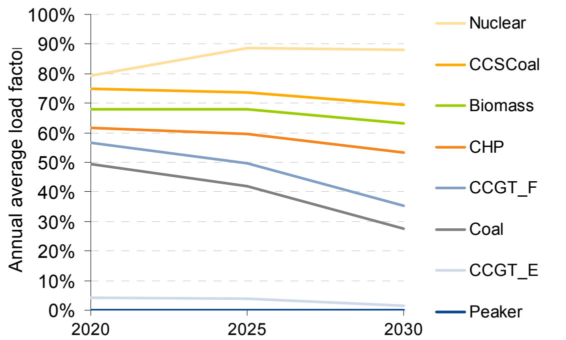
GB annual generation

% of total	2020	2025	2030
Wind + marine	23.5%	29.8%	34.7%
Hydro	1.3%	1.6%	1.7%
Biomass	5.7%	6.3%	6.2%
Nuclear	12.0%	15.1%	21.0%
CCSCoal	2.6%	2.7%	4.9%
CHP	9.7%	11.0%	10.6%
Coal	20.6%	11.5%	3.7%
CCGT	24.5%	22.1%	17.1%
Peaker	0.0%	0.0%	0.0%
RES %	30.5%	37.7%	42.6%

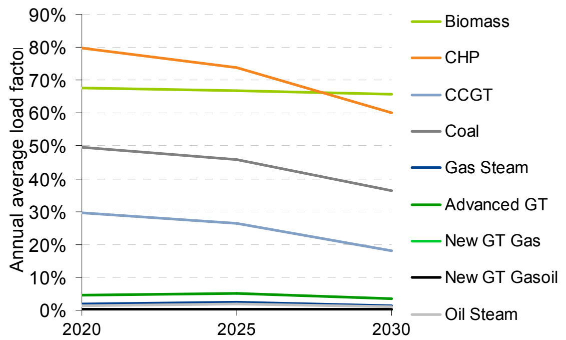
SEM annual generation

% of total	2020	2025	2030
Wind + marine	42.8%	49.5%	55.2%
Hydro	2.0%	1.8%	1.6%
Biomass	3.5%	4.6%	6.4%
CCSCoal	0.0%	0.0%	6.5%
CHP	2.9%	2.6%	2.0%
Coal	17.6%	15.6%	11.7%
CCGT	30.8%	25.3%	16.3%
Peaker	0.4%	0.5%	0.3%
RES %	48.3%	55.9%	63.2%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

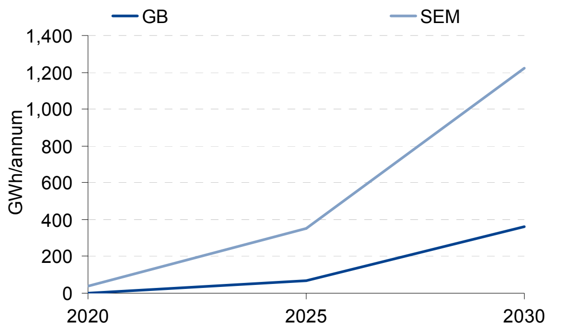
%	2020	2025	2030
Biomass	68%	68%	63%
Nuclear	79%	89%	88%
CCSCoal	75%	74%	70%
CHP	62%	60%	53%
CCGT_E	4%	4%	1%
CCGT_F	57%	50%	35%
Coal	50%	42%	28%
Peaker	<0.1%	<0.1%	<0.1%

SEM annual average load factor

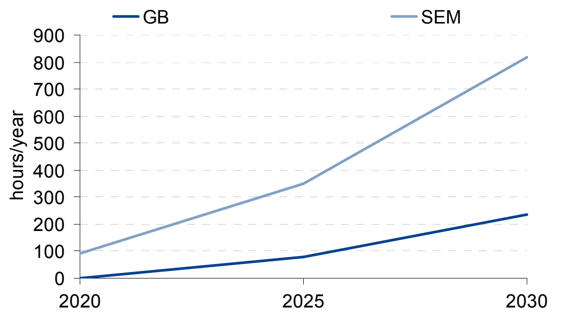
%	2020	2025	2030
Biomass	68%	67%	66%
CCSCoal			74%
CHP	80%	74%	60%
Coal	50%	46%	36%
CCGT	30%	26%	18%
Gas Steam	2%	3%	1%
Advanced GT	4.5%	5.2%	3.5%
New GT Gas	0.3%	0.1%	0.1%
New GT Gasoil	0.2%	0.3%	0.2%
Oil Steam	1.4%	1.9%	1.2%

C.6.2 Offshore Growth scenario page 3

Wind curtailment



Shedding periods



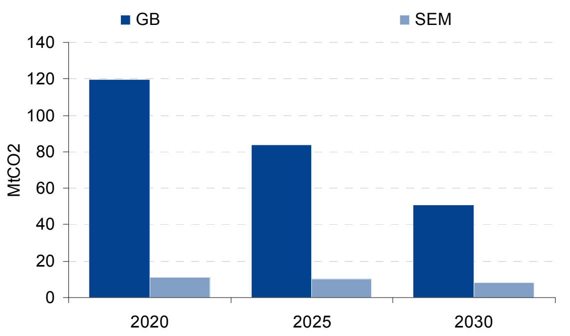
Wind curtailment

GWh/annum	2020	2025	2030
GB	0	68	361
SEM	37	350	1222

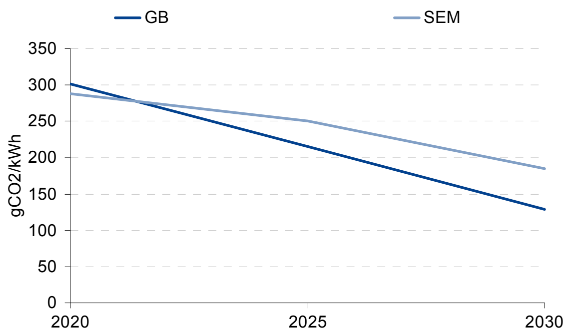
Shedding periods

hours/year	2020	2025	2030
GB	0	77	234
SEM	93	349	817

Carbon emissions



Carbon intensity



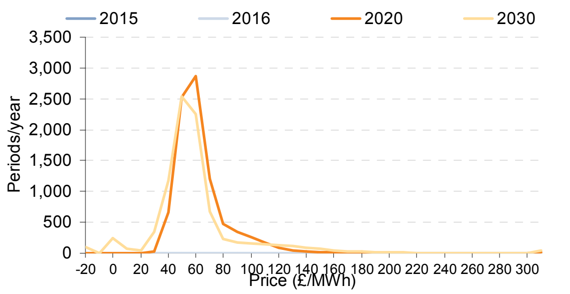
Carbon emissions

MtCO2	2020	2025	2030
GB	119	84	51
SEM	11	10	8

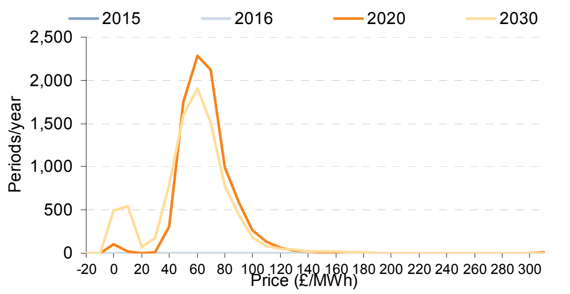
Carbon intensity

gCO2/kWh	2020	2025	2030
GB	301.1	215.4	128.9
SEM	288.6	250.1	184.1

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

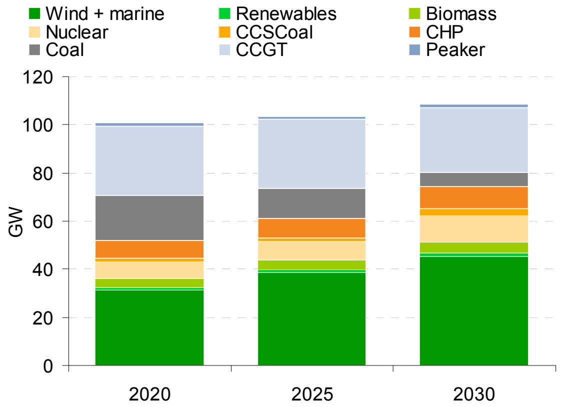
Periods/year	2020	2025	2030
<=0	5	114	335
0-20	3	28	120
20-50	3212	3398	4053
50-100	5135	4659	3497
100-200	381	521	683
>200	23	40	72

Price distribution (SEM)

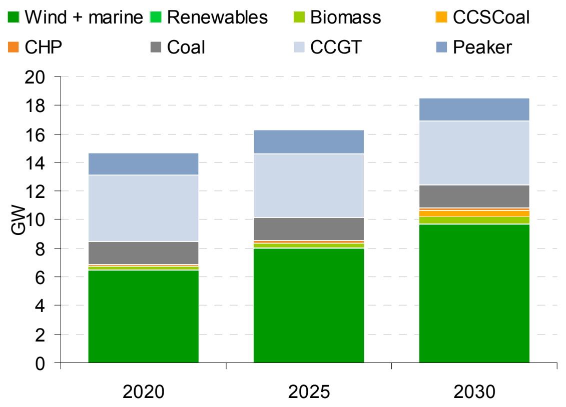
Periods/year	2020	2025	2030
<=0	104	286	496
0-20	26	192	613
20-50	2073	2187	2561
50-100	6263	5770	4808
100-200	276	305	270
>200	19	21	11

C.6.3 Offshore Growth scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2020	2025	2030
Wind + marine	31.1	38.5	45.4
Renewables	1.2	1.3	1.5
Biomass	3.8	4.1	4.4
Nuclear	6.9	7.6	10.7
CCSCoal	1.6	1.6	3.2
CHP	7.2	8.2	9.0
Coal	18.9	12.2	6.1
CCGT	28.9	28.9	26.7
Peaker	1.3	1.2	1.4
Total	100.8	103.5	108.4

Installed capacity (SEM)

GW	2020	2025	2030
Wind + marine	6.4	8.0	9.7
Renewables	0.1	0.1	0.1
Biomass	0.2	0.3	0.5
CCSCoal			0.4
CHP	0.2	0.2	0.2
Coal	1.6	1.6	1.6
CCGT	4.6	4.5	4.5
Peaker	1.6	1.7	1.6
Total	14.7	16.3	18.5

Installed capacity mix (SEM)

GW	2020	2025	2030
Wind + marine	31%	37%	42%
Renewables	1%	1%	1%
Biomass	4%	4%	4%
Nuclear	7%	7%	10%
CCSCoal	2%	2%	3%
CHP	7%	8%	8%
Coal	19%	12%	6%
CCGT	29%	28%	25%
Peaker	1%	1%	1%

Installed capacity mix (SEM)

GW	2020	2025	2030
Wind + marine	44%	49%	52%
Renewables	1%	1%	0%
Biomass	2%	2%	3%
CCSCoal	0%	0%	2%
CHP	1%	1%	1%
Coal	11%	10%	9%
CCGT	32%	28%	24%
Peaker	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	11488	11488	11488	11488
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3546	3546	3546	3546	3546	3315
	2027	2028	2029	2030		
Thermal	5362	2592	4556	740		
Renewable	3315	3315	3315	3315		

Investment cost (SEM)

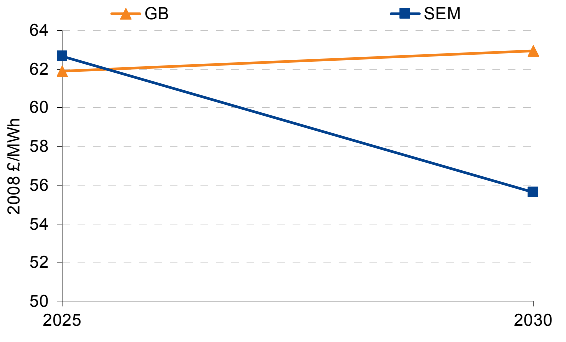
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1013	1013	1013	1013
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	574	574	574	574	574	637
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	637	637	637	637		

Lost Load

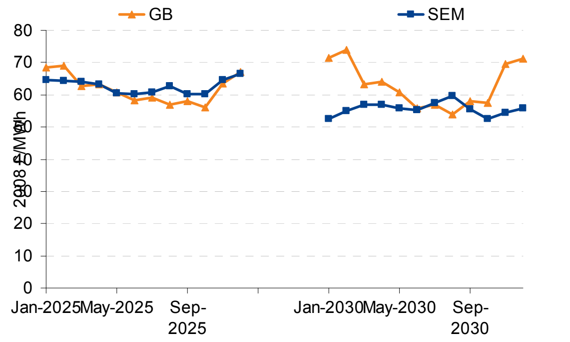
MW	2020	2025	2030
GB	62	383	1798
SEM	0	0	0

C.7 Severn Barrage scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2025	2030
GB	61.9	63.0
SEM	62.7	55.6
	2025	2030
€ per £	1.08	1.08
SEM (2008 €/MWh)	67.5	59.9

Monthly wholesale price

2008 £/MWh	2025	2030
GB - Jan	68.6	71.5
GB - May	60.9	60.9
GB - Sep	58.0	58.1
SEM - Jan	68.6	71.5
SEM - May	60.9	60.9
SEM - Sep	58.0	58.1

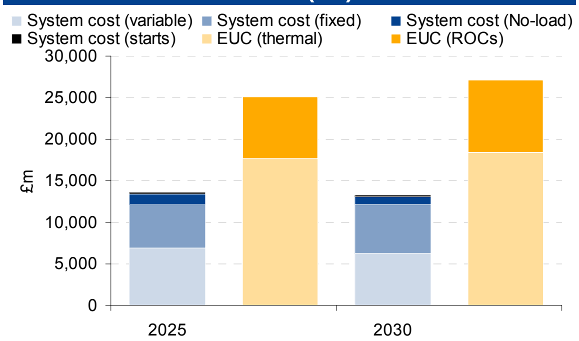
Internal Rate of Return (GB)

	2025	2030
Nuclear	11.4%	11.5%
CCSCoal	6.3%	6.3%
Coal	3.4%	3.9%
CCGT_F	8.0%	9.4%
OCGT	<0	<0

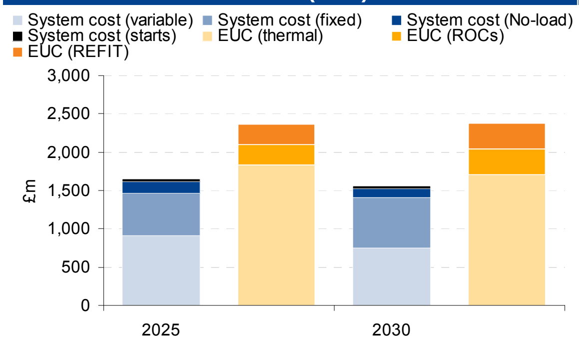
Internal rate of Return (SEM)

	2025	2030
CCGT	6.1%	5.8%
CCSCoal	N/A	4.3%
LMS100	5.5%	5.6%
OCGT (Gasoil)	8.1%	8.4%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

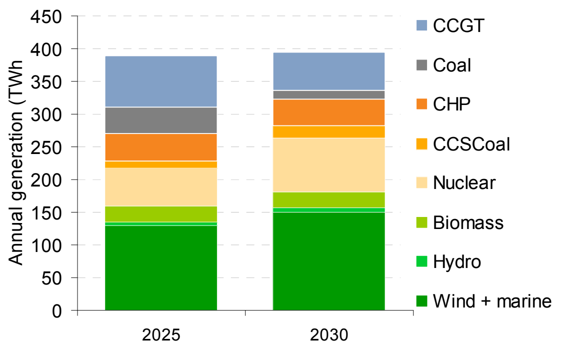
		2025	2030
System cost	Variable	6864	6272
	Fixed	5242	5829
	No-Load	1303	996
	Starts	193	193
EUC	Thermal	17653	18414
	ROCs	7476	8747

End user cost vs annual cost (SEM)

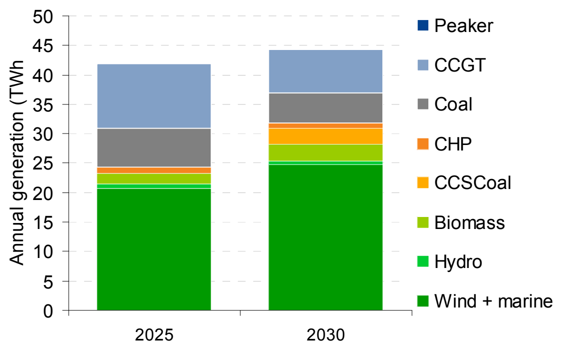
		2025	2030
System cost	Variable	910	749
	Fixed	558	662
	No-Load	150	115
	Starts	29	28
EUC	Thermal	1830	1712
	ROCs	267	335
	REFIT	251	308

C.7.1 Severn Barrage scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2025	2030
Wind + marine	129.4	150.6
Hydro	6.0	6.7
Biomass	24.3	23.9
Nuclear	58.5	82.2
CCSCoal	10.2	19.1
CHP	42.0	40.6
Coal	39.9	13.2
CCGT	78.2	58.3
Peaker	0.0	0.0
Total	388.5	394.6

SEM annual generation

TWh	2025	2030
Wind + marine	20.7	24.7
Hydro	0.7	0.7
Biomass	1.9	2.8
CCSCoal	0.0	2.7
CHP	1.1	0.9
Coal	6.6	5.2
CCGT	10.9	7.4
Peaker	0.1	0.1
Total	42.0	44.4

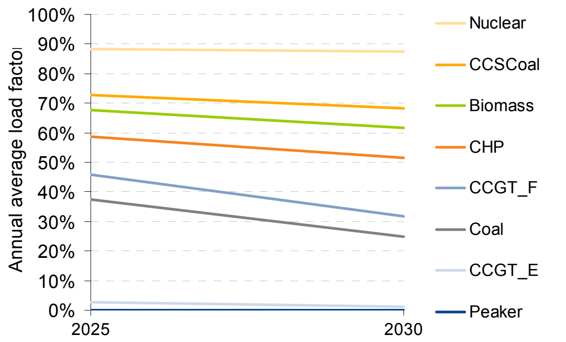
GB annual generation

% of total	2025	2030
Wind + marine	33.3%	38.2%
Hydro	1.5%	1.7%
Biomass	6.3%	6.0%
Nuclear	15.1%	20.8%
CCSCoal	2.6%	4.8%
CHP	10.8%	10.3%
Coal	10.3%	3.4%
CCGT	20.1%	14.8%
Peaker	0.0%	0.0%
RES %	41.1%	45.9%

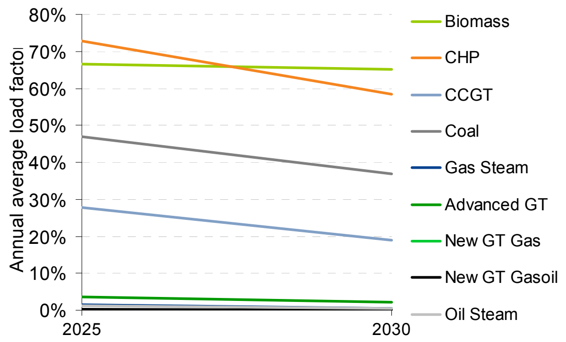
SEM annual generation

% of total	2025	2030
Wind + marine	49.3%	55.7%
Hydro	1.8%	1.5%
Biomass	4.4%	6.2%
CCSCoal	0.0%	6.2%
CHP	2.5%	1.9%
Coal	15.7%	11.6%
CCGT	26.0%	16.7%
Peaker	0.3%	0.1%
RES %	55.5%	63.4%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

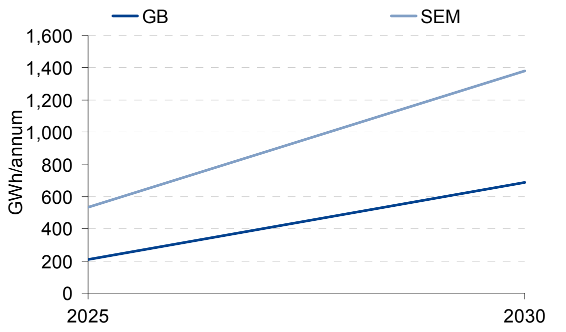
%	2025	2030
Biomass	68%	62%
Nuclear	88%	88%
CCSCoal	73%	68%
CHP	59%	52%
CCGT_E	3%	1%
CCGT_F	46%	32%
Coal	37%	25%
Peaker	<0.1%	<0.1%

SEM annual average load factor

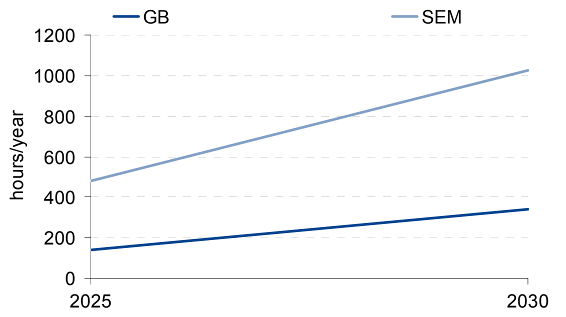
%	2025	2030
Biomass	67%	65%
CCSCoal		71%
CHP	73%	58%
Coal	47%	37%
CCGT	28%	19%
Gas Steam	1%	0%
Advanced GT	3.5%	2.1%
New GT Gas	<0.1%	<0.1%
New GT Gasoil	0.1%	<0.1%
Oil Steam	1.1%	0.4%

C.7.2 Severn Barrage scenario page 3

Wind curtailment



Shedding periods



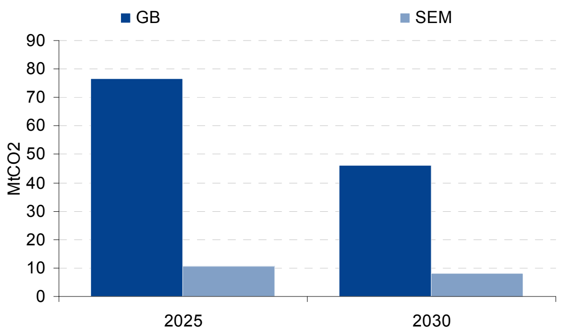
Wind curtailment

GWh/annum	2025	2030
GB	209	688
SEM	535	1378

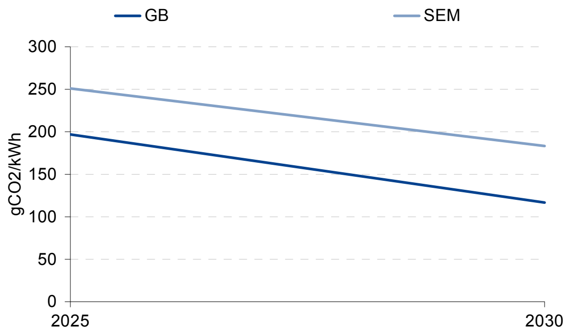
Shedding periods

hours/year	2025	2030
GB	138	342
SEM	481	1026

Carbon emissions



Carbon intensity



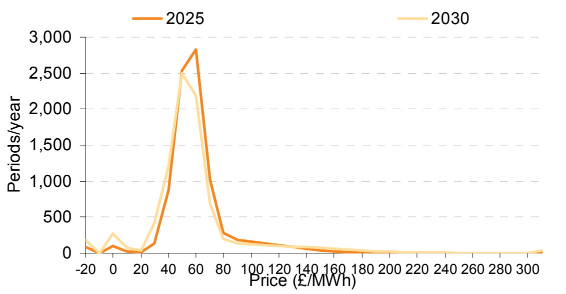
Carbon emissions

MtCO2	2025	2030
GB	77	46
SEM	11	8

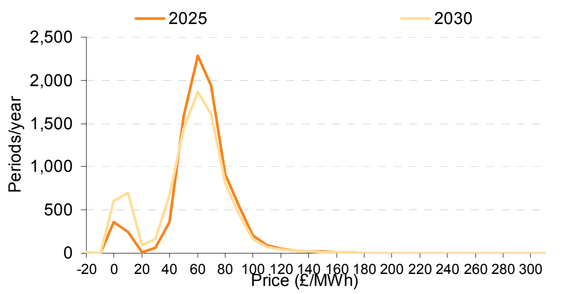
Carbon intensity

gCO2/kWh	2025	2030
GB	197.2	116.4
SEM	251.1	183.4

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

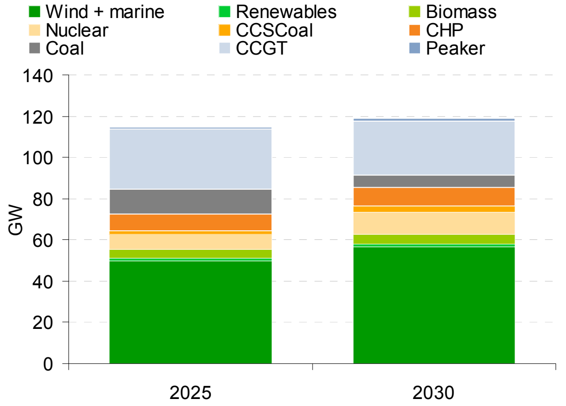
Periods/year	2025	2030
<=0	183	451
0-20	38	121
20-50	3538	4111
50-100	4476	3334
100-200	492	646
>200	34	98

Price distribution (SEM)

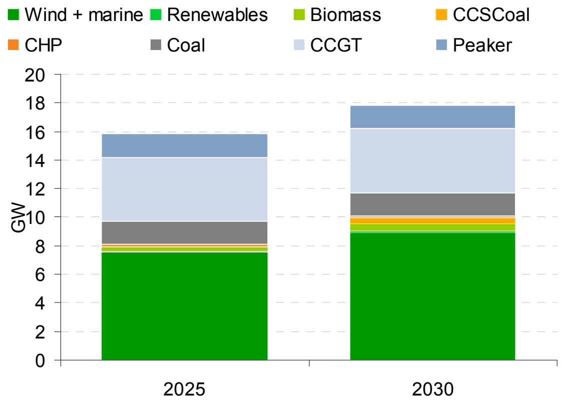
Periods/year	2025	2030
<=0	362	611
0-20	260	782
20-50	2006	2279
50-100	5872	4872
100-200	246	205
>200	15	10

C.7.3 Severn Barrage scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2025	2030
Wind + marine	49.8	56.7
Renewables	1.3	1.5
Biomass	4.1	4.4
Nuclear	7.6	10.7
CCSCoal	1.6	3.2
CHP	8.2	9.0
Coal	12.2	6.1
CCGT	28.9	25.9
Peaker	1.2	1.4
Total	114.9	118.9

Installed capacity (SEM)

GW	2025	2030
Wind + marine	7.5	8.9
Renewables	0.1	0.1
Biomass	0.3	0.5
CCSCoal		0.4
CHP	0.2	0.2
Coal	1.6	1.6
CCGT	4.5	4.5
Peaker	1.7	1.6
Total	15.9	17.8

Installed capacity mix (SEM)

GW	2025	2030
Wind + marine	43%	48%
Renewables	1%	1%
Biomass	4%	4%
Nuclear	7%	9%
CCSCoal	1%	3%
CHP	7%	8%
Coal	11%	5%
CCGT	25%	22%
Peaker	1%	1%

Installed capacity mix (SEM)

GW	2025	2030
Wind + marine	47%	50%
Renewables	1%	1%
Biomass	2%	3%
CCSCoal	0%	2%
CHP	1%	1%
Coal	10%	9%
CCGT	28%	25%
Peaker	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	2582	2582	2582	2582	27292	3395
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

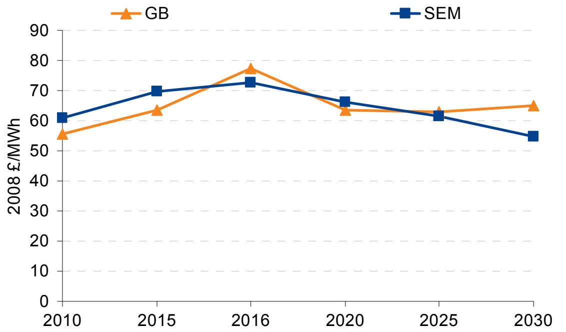
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

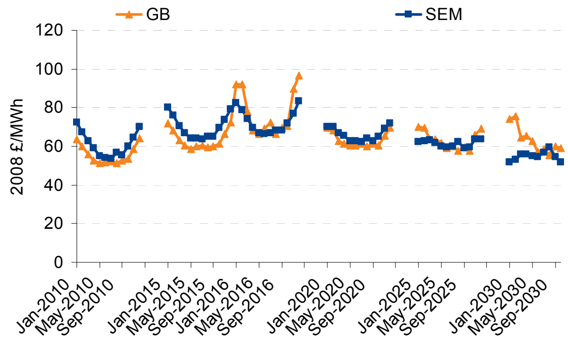
MW	2025	2030
GB	570	3077
SEM	0	0

C.8 Interconnection scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.6	63.5	77.5	63.4	63.1	65.0
SEM	60.9	69.8	72.8	66.1	61.5	54.7
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	66.2	75.2	78.4	71.2	66.2	58.9

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	63.5	72.1	92.1	69.6	70.0	74.2
GB - May	51.3	58.6	66.5	60.4	61.6	62.5
GB - Sep	52.6	60.2	69.4	61.3	59.4	60.1
SEM - Jan	63.5	72.1	92.1	69.6	70.0	74.2
SEM - May	51.3	58.6	66.5	60.4	61.6	62.5
SEM - Sep	52.6	60.2	69.4	61.3	59.4	60.1

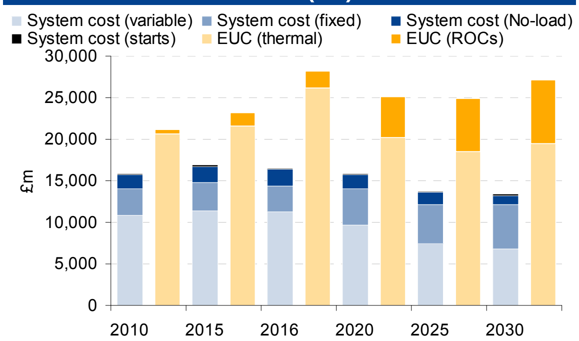
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.3%	11.8%	12.0%
CCSCoal	N/A	N/A	N/A	6.6%	6.7%	6.8%
Coal	N/A	N/A	3.9%	3.0%	3.8%	4.4%
CCGT_F	5.2%	8.2%	8.8%	6.6%	8.6%	10.2%
OCGT	<0	<0	<0	<0	<0	<0

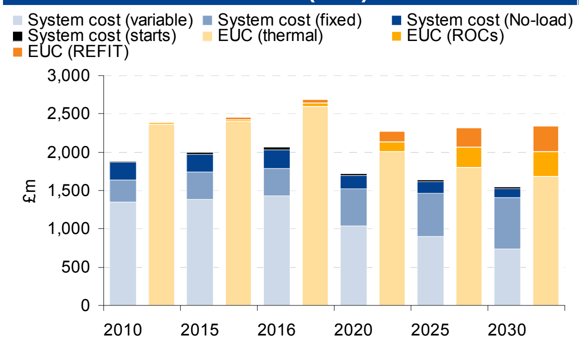
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	7.2%	7.0%	6.4%	5.7%	5.5%
CCSCoal	N/A	N/A	N/A	N/A	N/A	4.1%
LMS100	N/A	1.7%	2.6%	5.2%	5.1%	5.2%
OCGT (Gasoil)	8.3%	8.3%	8.3%	8.1%	8.0%	8.4%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

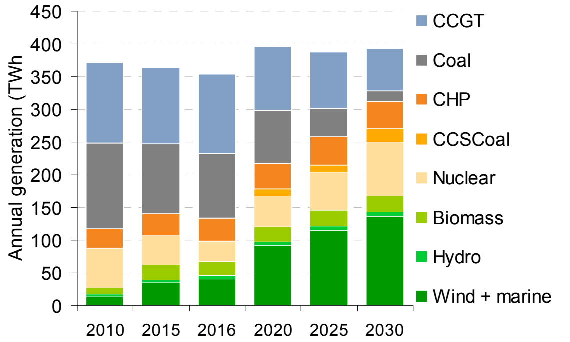
		2010	2015	2016	2020	2025	2030
System cost	Variable	10805	11396	11276	9677	7449	6805
	Fixed	3281	3414	3129	4390	4730	5317
	No-Load	1637	1904	1928	1652	1395	1087
	Starts	134	161	152	175	178	179
EUC	Thermal	20619	21591	26205	20191	18562	19496
	ROCs	532	1599	1944	4910	6374	7654

End user cost vs annual cost (SEM)

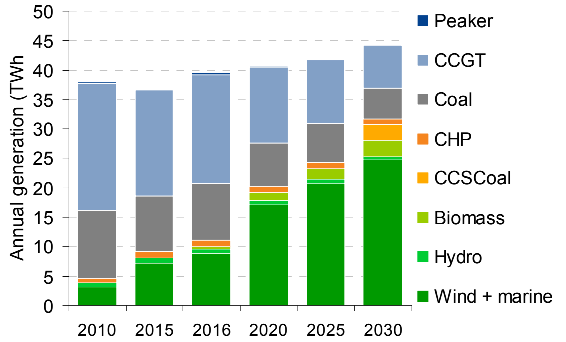
		2010	2015	2016	2020	2025	2030
System cost	Variable	1350	1389	1436	1038	906	742
	Fixed	290	348	352	481	558	662
	No-Load	225	233	241	173	149	114
	Starts	21	29	35	29	28	27
EUC	Thermal	2369	2395	2599	2010	1796	1683
	ROCs	14	31	45	129	264	327
	REFIT	25	63	79	179	250	306

C.8.1 Interconnection scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.0	6.8
Biomass	9.9	22.5	22.5	22.5	24.3	24.6
Nuclear	60.2	44.5	30.4	47.7	58.6	82.8
CCSCoal	0.0	0.0	0.0	10.5	10.3	19.7
CHP	29.2	34.0	34.9	38.6	42.9	42.4
Coal	131.8	107.3	99.6	81.2	44.0	15.2
CCGT	123.1	115.8	120.8	97.1	85.6	65.8
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.9	363.4	354.0	395.4	387.2	393.6

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.7	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.7
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.7
CHP	0.7	1.1	1.1	1.1	1.1	0.9
Coal	11.6	9.5	9.5	7.3	6.6	5.2
CCGT	21.5	18.0	18.6	12.9	10.9	7.3
Peaker	0.2	0.1	0.3	0.1	0.1	0.0
Total	38.0	36.8	39.6	40.6	41.9	44.2

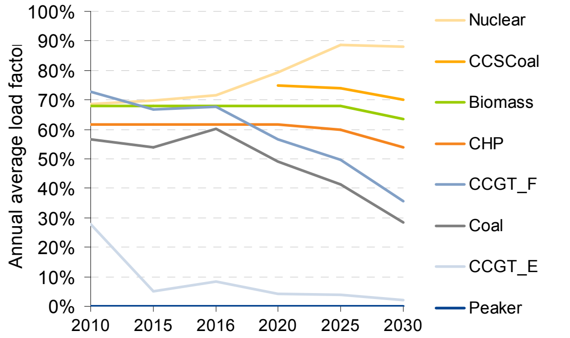
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	9.5%	11.5%	23.4%	29.8%	34.7%
Hydro	1.3%	1.3%	1.4%	1.4%	1.6%	1.7%
Biomass	2.7%	6.2%	6.3%	5.7%	6.3%	6.2%
Nuclear	16.2%	12.2%	8.6%	12.1%	15.1%	21.0%
CCSCoal	0.0%	0.0%	0.0%	2.7%	2.7%	5.0%
CHP	7.8%	9.4%	9.9%	9.8%	11.1%	10.8%
Coal	35.4%	29.5%	28.1%	20.5%	11.4%	3.9%
CCGT	33.1%	31.9%	34.1%	24.6%	22.1%	16.7%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	17.0%	19.3%	30.4%	37.6%	42.6%

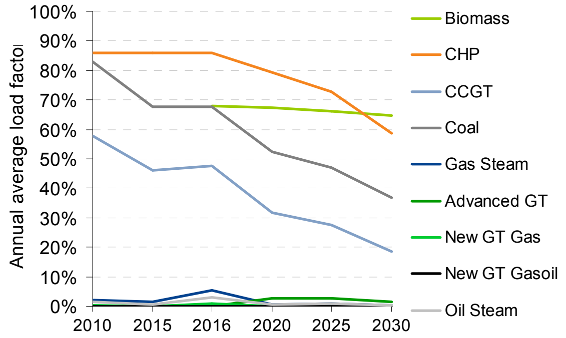
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.4%	19.7%	22.3%	42.0%	49.4%	55.9%
Hydro	2.1%	2.1%	2.0%	1.9%	1.7%	1.5%
Biomass	0.0%	0.0%	1.1%	3.3%	4.4%	6.2%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%
CHP	1.8%	3.1%	2.9%	2.8%	2.5%	1.9%
Coal	30.5%	25.8%	23.9%	18.0%	15.7%	11.7%
CCGT	56.6%	48.9%	46.9%	31.8%	26.0%	16.6%
Peaker	0.6%	0.3%	0.9%	0.2%	0.2%	0.1%
RES %	10.5%	21.9%	25.4%	47.2%	55.5%	63.6%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

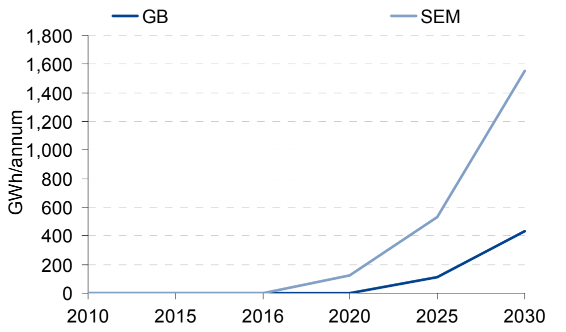
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	64%
Nuclear	68%	70%	72%	79%	89%	88%
CCSCoal				75%	74%	70%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	28%	5%	8%	4%	4%	2%
CCGT_F	73%	67%	68%	57%	50%	36%
Coal	57%	54%	60%	49%	41%	28%
Peaker	<0.1%	<0.1%	0.10%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

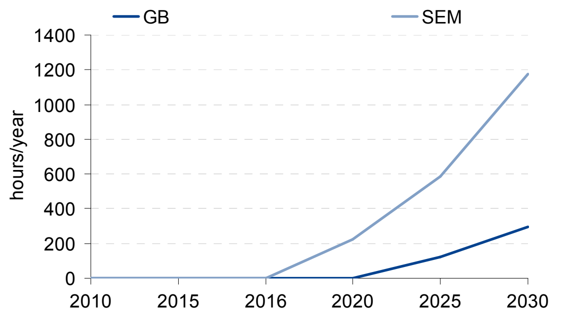
%	2010	2015	2016	2020	2025	2030
Biomass			68%	67%	66%	65%
CCSCoal						70%
CHP	86%	86%	86%	79%	73%	59%
Coal	83%	68%	68%	52%	47%	37%
CCGT	58%	46%	48%	32%	28%	19%
Gas Steam	2%	1%	5%	1%	1%	0%
Advanced GT	<0.1%	<0.1%	<0.1%	2.6%	2.7%	1.5%
New GT Gas	0.2%	<0.1%	0.9%	<0.1%	<0.1%	<0.1%
New GT Gasoil	<0.1%	<0.1%	0.1%	<0.1%	<0.1%	<0.1%
Oil Steam	1.4%	0.7%	3.0%	0.7%	0.8%	0.2%

C.8.2 Interconnection scenario page 3

Wind curtailment



Shedding periods



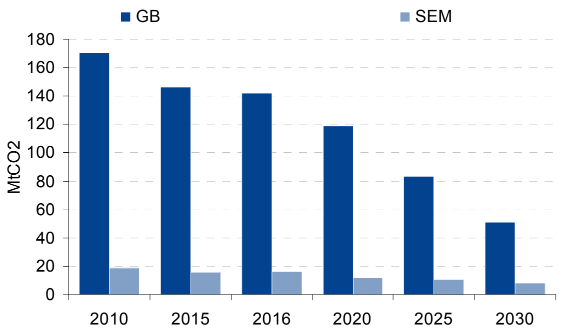
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	110	430
SEM	0	0	0	122	529	1553

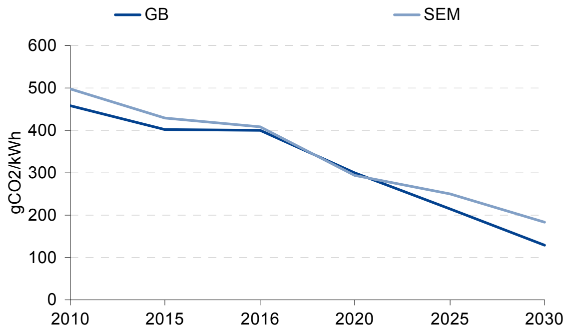
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	121	295
SEM	0	0	0	222	587	1177

Carbon emissions



Carbon intensity



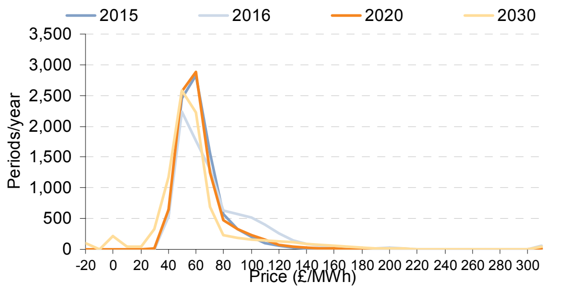
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	146	142	119	83	51
SEM	19	16	16	12	10	8

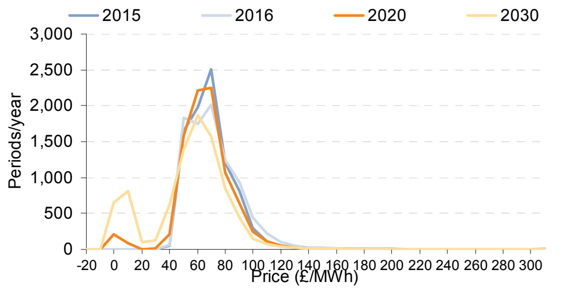
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.1	402.8	400.3	300.4	214.7	129.1
SEM	497.2	428.8	407.7	293.6	250.7	182.8

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

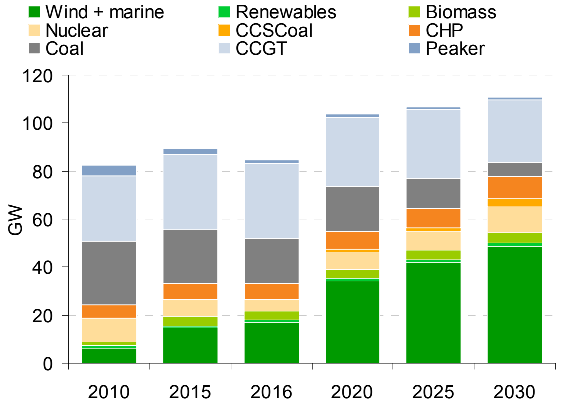
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	4	92	303
0-20	0	0	0	3	19	87
20-50	5134	3009	2779	3242	3474	4094
50-100	3523	5489	4795	5160	4686	3494
100-200	98	254	1072	333	460	706
>200	6	9	114	19	30	77

Price distribution (SEM)

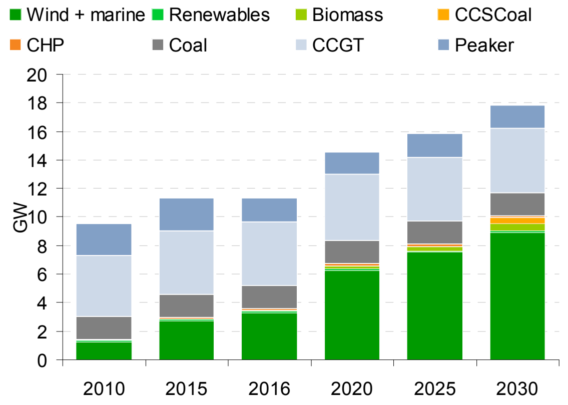
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	213	416	659
0-20	0	0	0	93	374	908
20-50	3558	1690	1889	1799	1870	2116
50-100	5076	6813	6363	6412	5897	4891
100-200	119	246	482	227	190	179
>200	7	10	26	16	14	8

C.8.3 Interconnection scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	28.9	28.9	25.9
Peaker	4.7	2.7	1.7	1.3	1.2	1.4
Total	82.5	89.6	84.8	103.8	106.9	110.9

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	20%	33%	39%	44%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	10%
CCSCoal	0%	0%	0%	2%	1%	3%
CHP	7%	7%	8%	7%	8%	8%
Coal	32%	25%	22%	18%	11%	6%
CCGT	33%	35%	37%	28%	27%	23%
Peaker	6%	3%	2%	1%	1%	1%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

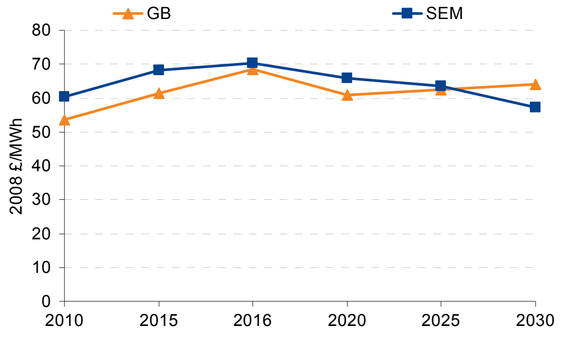
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

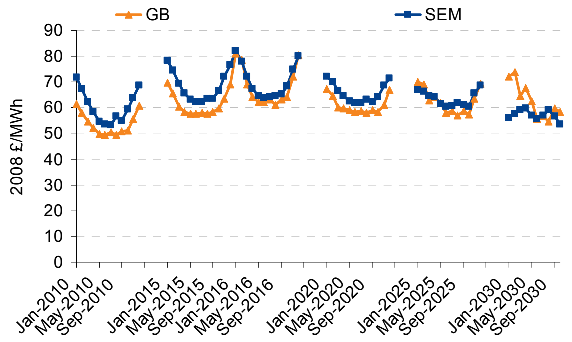
MW	2010	2015	2016	2020	2025	2030
GB	0	0	2405	218	708	4123
SEM	0	0	0	0	0	0

C.9 Inflexible Demand Management scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	53.7	61.3	68.4	60.9	62.5	63.9
SEM	60.4	68.2	70.4	65.8	63.5	57.2
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	65.8	73.4	75.9	70.9	68.4	61.7

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	61.4	69.8	80.9	67.3	70.2	72.0
GB - May	49.9	57.8	62.3	59.0	61.7	62.6
GB - Sep	50.8	58.3	63.2	59.0	58.9	59.7
SEM - Jan	61.4	69.8	80.9	67.3	70.2	72.0
SEM - May	49.9	57.8	62.3	59.0	61.7	62.6
SEM - Sep	50.8	58.3	63.2	59.0	58.9	59.7

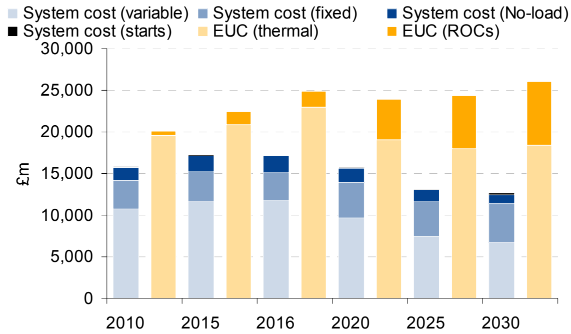
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	11.0%	11.5%	11.7%
CCSCoal	N/A	N/A	N/A	6.0%	6.2%	6.2%
Coal	N/A	N/A	2.0%	2.0%	3.0%	3.4%
CCGT_F	1.1%	4.2%	4.7%	4.8%	7.1%	8.5%
OCGT	<0	<0	<0	<0	<0	<0

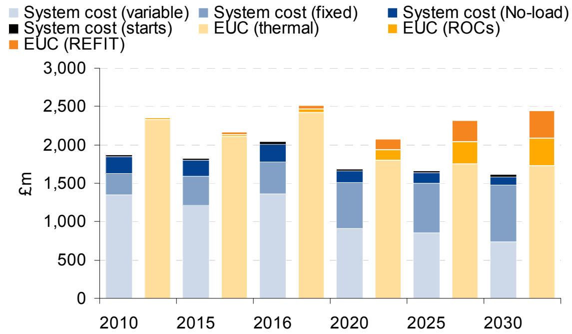
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	6.2%	6.1%	6.3%	6.1%	6.0%
CCSCoal	N/A	N/A	N/A	N/A	N/A	4.4%
LMS100	N/A	2.0%	2.9%	5.7%	6.0%	6.2%
OCGT (Gasoil)	8.1%	8.1%	8.2%	8.1%	8.1%	8.4%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

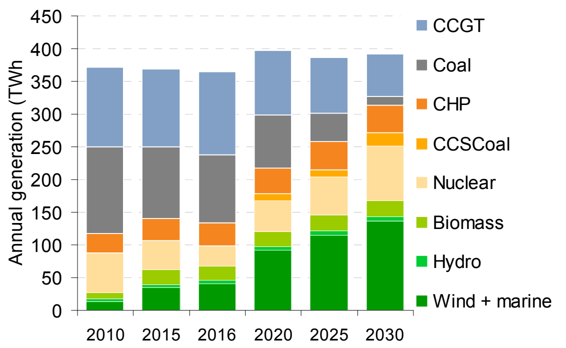
		2010	2015	2016	2020	2025	2030
System cost	Variable	10780	11660	11799	9731	7404	6676
	Fixed	3324	3544	3268	4205	4317	4740
	No-Load	1625	1950	2012	1664	1395	1070
	Starts	82	87	77	112	117	124
EUC	Thermal	19584	20885	22936	19065	17976	18456
	ROCs	532	1599	1944	4910	6374	7658

End user cost vs annual cost (SEM)

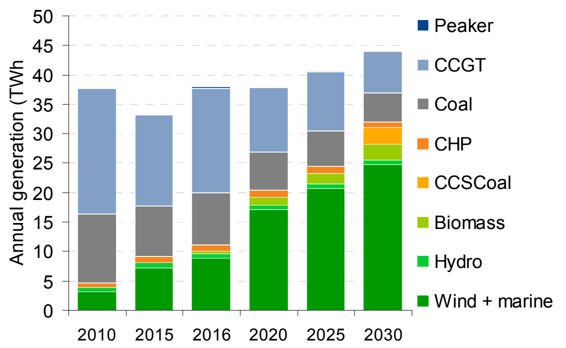
		2010	2015	2016	2020	2025	2030
System cost	Variable	1346	1213	1362	906	850	738
	Fixed	279	383	418	602	652	735
	No-Load	224	203	230	149	139	113
	Starts	16	21	30	24	26	26
EUC	Thermal	2336	2106	2427	1804	1757	1730
	ROCs	14	31	45	134	280	357
	REFIT	25	63	79	180	254	313

C.9.1 Inflexible Demand Management scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.1	6.8
Biomass	9.9	22.5	22.5	22.5	24.4	24.7
Nuclear	60.2	44.5	30.4	47.7	58.7	83.2
CCSCoal	0.0	0.0	0.0	10.5	10.4	19.8
CHP	29.2	34.0	34.9	38.7	43.3	42.5
Coal	133.5	110.0	104.9	81.4	43.1	13.9
CCGT	121.3	118.7	126.7	98.4	85.8	64.4
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.7	369.1	365.0	397.0	387.1	391.8

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.9
CHP	0.7	1.1	1.1	1.2	1.1	0.9
Coal	11.7	8.5	8.7	6.5	6.1	5.0
CCGT	21.4	15.5	17.7	10.9	10.0	7.1
Peaker	0.2	0.0	0.3	0.1	0.2	0.1
Total	37.9	33.2	38.0	37.9	40.7	44.2

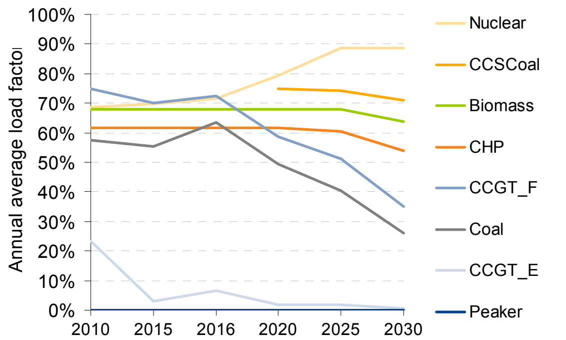
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	9.3%	11.2%	23.3%	29.8%	34.8%
Hydro	1.3%	1.3%	1.3%	1.3%	1.6%	1.7%
Biomass	2.7%	6.1%	6.2%	5.7%	6.3%	6.3%
Nuclear	16.2%	12.0%	8.3%	12.0%	15.2%	21.2%
CCSCoal	0.0%	0.0%	0.0%	2.6%	2.7%	5.1%
CHP	7.8%	9.2%	9.6%	9.7%	11.2%	10.8%
Coal	35.9%	29.8%	28.7%	20.5%	11.1%	3.5%
CCGT	32.6%	32.2%	34.7%	24.8%	22.2%	16.4%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	16.8%	18.7%	30.3%	37.6%	42.9%

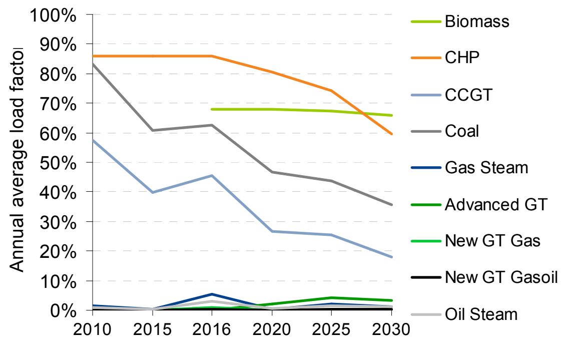
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.4%	21.9%	23.2%	45.1%	50.9%	56.0%
Hydro	2.1%	2.4%	2.1%	2.1%	1.9%	1.6%
Biomass	0.0%	0.0%	1.2%	3.6%	4.6%	6.3%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	6.5%
CHP	1.8%	3.4%	3.0%	3.1%	2.7%	2.0%
Coal	30.8%	25.6%	23.0%	17.2%	15.0%	11.3%
CCGT	56.5%	46.6%	46.7%	28.8%	24.5%	16.1%
Peaker	0.4%	0.1%	0.9%	0.2%	0.4%	0.3%
RES %	10.5%	24.2%	26.4%	50.7%	57.4%	63.9%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

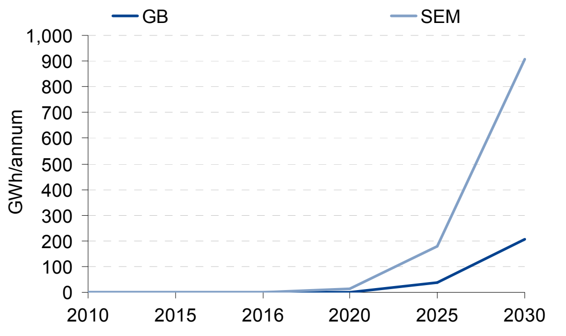
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	64%
Nuclear	68%	70%	72%	79%	89%	89%
CCSCoal				75%	74%	71%
CHP	62%	62%	62%	62%	60%	54%
CCGT_E	23%	3%	6%	2%	2%	1%
CCGT_F	75%	70%	73%	59%	51%	35%
Coal	57%	55%	63%	49%	41%	26%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

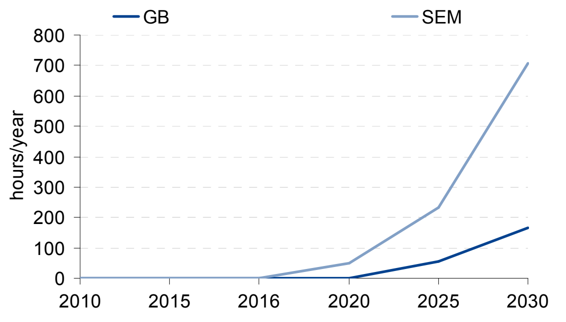
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						74%
CHP	86%	86%	86%	81%	74%	60%
Coal	83%	61%	62%	47%	44%	36%
CCGT	58%	40%	46%	27%	25%	18%
Gas Steam	1%	0%	5%	0%	2%	1%
Advanced GT	<0.1%	<0.1%	<0.1%	2.0%	4.2%	3.2%
New GT Gas	0.1%	<0.1%	0.8%	<0.1%	0.1%	<0.1%
New GT Gasoil	<0.1%	<0.1%	0.2%	<0.1%	0.2%	0.2%
Oil Steam	1.0%	0.3%	3.0%	0.5%	1.5%	1.1%

C.9.2 *Inflexible Demand Management scenario page 3*

Wind curtailment



Shedding periods



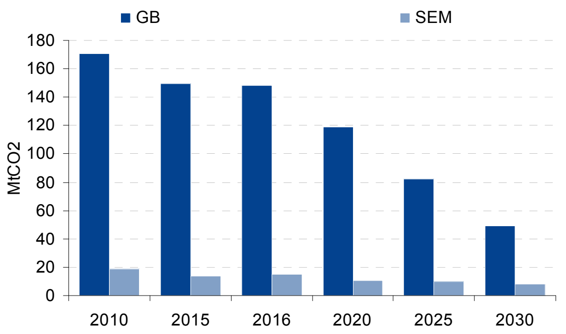
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	38	207
SEM	0	0	0	15	178	908

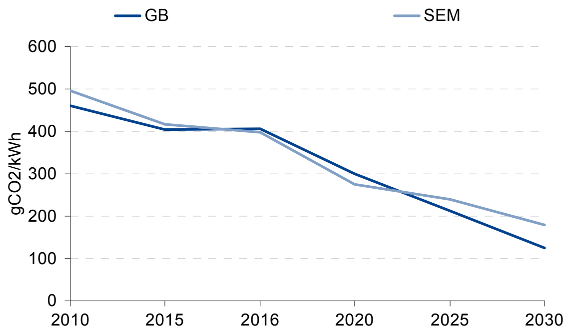
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	55	165
SEM	0	0	0	50	232	706

Carbon emissions



Carbon intensity



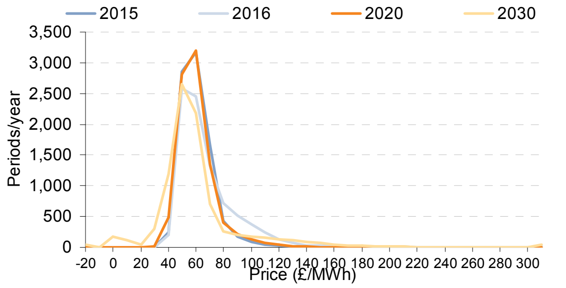
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	149	148	119	82	49
SEM	19	14	15	10	10	8

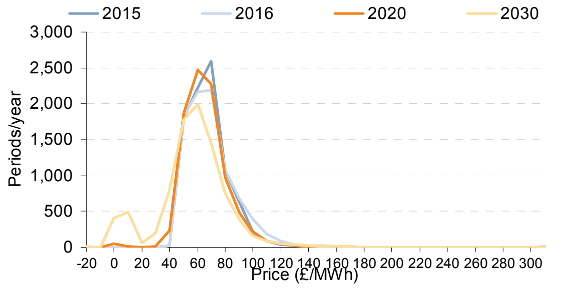
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.7	404.6	405.3	299.7	212.1	124.9
SEM	496.8	417.3	398.1	275.7	240.6	178.7

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

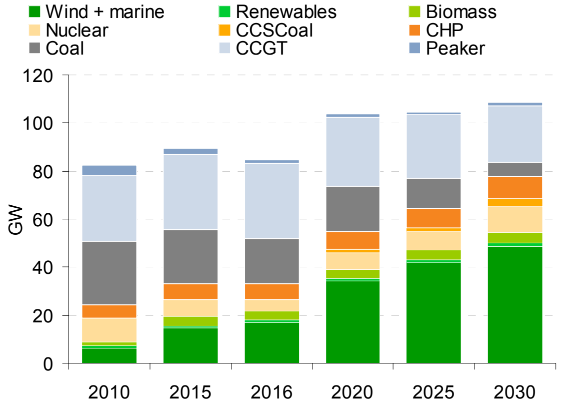
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	1	41	215
0-20	0	0	0	2	32	151
20-50	5610	3089	2792	3304	3495	4140
50-100	3077	5541	5368	5277	4756	3504
100-200	68	126	569	171	415	682
>200	4	4	31	6	21	68

Price distribution (SEM)

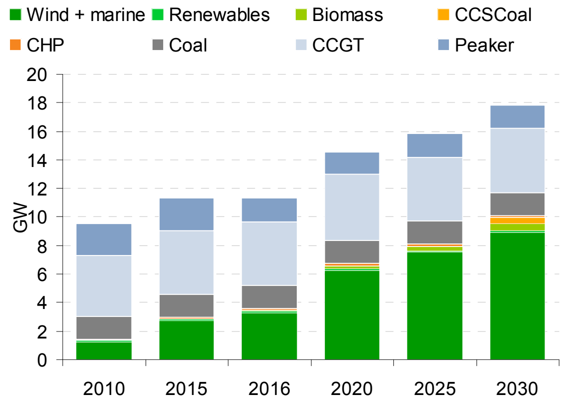
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	53	196	420
0-20	0	0	0	14	128	557
20-50	3658	1837	1863	2106	2354	2783
50-100	4996	6737	6506	6401	5811	4746
100-200	98	176	374	177	257	245
>200	8	9	18	10	14	9

C.9.3 Inflexible Demand Management scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	28.9	26.5	23.4
Peaker	4.7	2.7	1.7	1.3	1.2	1.4
Total	82.5	89.6	84.8	103.8	104.5	108.4

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	20%	33%	40%	45%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	10%
CCSCoal	0%	0%	0%	2%	2%	3%
CHP	7%	7%	8%	7%	8%	8%
Coal	32%	25%	22%	18%	12%	6%
CCGT	33%	35%	37%	28%	25%	22%
Peaker	6%	3%	2%	1%	1%	1%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	7622	21	3282	4258	3282	4258
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	3282	3421	5629	5629	5629	5629
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	2012	2012	2012	2012	2012	1589
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	1589	1589	1589	1589		

Investment cost (SEM)

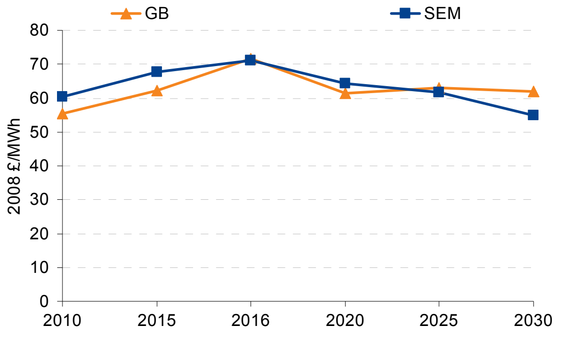
£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	905	1880	905	1880
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	905	1252	1594	1594	1594	1594
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	389	389	389	389	389	476
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	476	476	476	476		

Lost Load

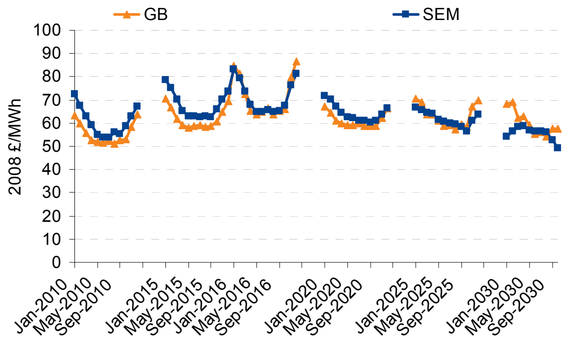
MW	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	27	904
SEM	0	0	0	0	0	0

C.10 Price Responsive Demand Management scenario

Annual wholesale price



Monthly wholesale price



Annual wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB	55.6	62.2	71.7	61.3	63.1	61.9
SEM	60.4	67.7	71.2	64.4	61.8	55.0
	2010	2015	2016	2020	2025	2030
€ per £	1.09	1.08	1.08	1.08	1.08	1.08
SEM (2008 €/MWh)	65.7	73.0	76.7	69.4	66.6	59.3

Monthly wholesale price

2008 £/MWh	2010	2015	2016	2020	2025	2030
GB - Jan	63.5	70.6	84.6	67.3	70.5	68.5
GB - May	51.7	58.1	63.6	59.1	61.0	59.2
GB - Sep	52.7	58.7	65.3	59.0	59.6	57.8
SEM - Jan	63.5	70.6	84.6	67.3	70.5	68.5
SEM - May	51.7	58.1	63.6	59.1	61.0	59.2
SEM - Sep	52.7	58.7	65.3	59.0	59.6	57.8

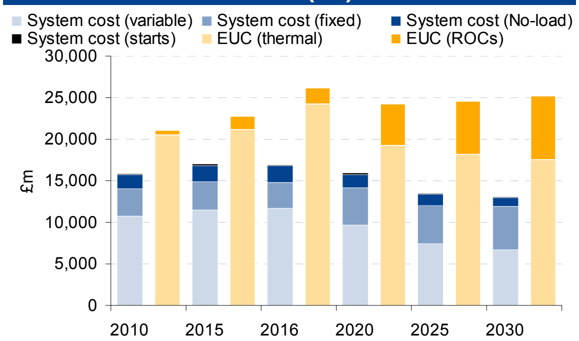
Internal Rate of Return (GB)

	2010	2015	2016	2020	2025	2030
Nuclear	N/A	N/A	N/A	10.9%	11.3%	11.2%
CCSCoal	N/A	N/A	N/A	5.7%	5.5%	5.3%
Coal	N/A	N/A	1.9%	1.2%	1.6%	1.7%
CCGT_F	2.6%	4.5%	4.9%	3.6%	4.9%	5.5%
OCGT	<0	<0	<0	<0	<0	<0

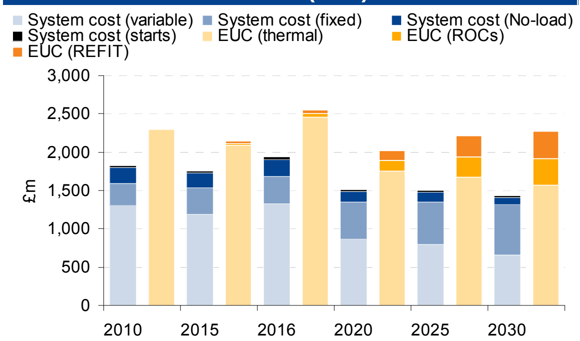
Internal rate of Return (SEM)

	2010	2015	2016	2020	2025	2030
CCGT	N/A	6.1%	6.1%	5.5%	5.0%	4.7%
CCSCoal	N/A	N/A	N/A	N/A	N/A	3.6%
LMS100	N/A	1.9%	2.8%	5.5%	5.5%	5.5%
OCGT (Gasoil)	8.5%	8.6%	8.6%	8.2%	8.2%	8.4%

End user cost vs annual cost (GB)



End user cost vs annual cost (SEM)



End user cost vs annual cost (GB)

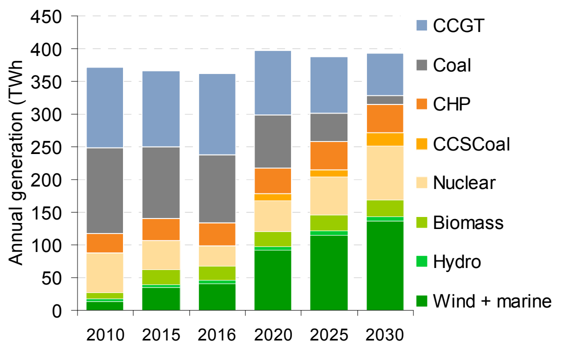
		2010	2015	2016	2020	2025	2030
System cost	Variable	10792	11525	11680	9727	7405	6684
	Fixed	3281	3414	3129	4390	4628	5215
	No-Load	1634	1920	1987	1658	1390	1066
	Starts	131	131	111	131	107	90
EUC	Thermal	20552	21172	24257	19294	18204	17574
	ROCs	532	1599	1944	4910	6374	7659

End user cost vs annual cost (SEM)

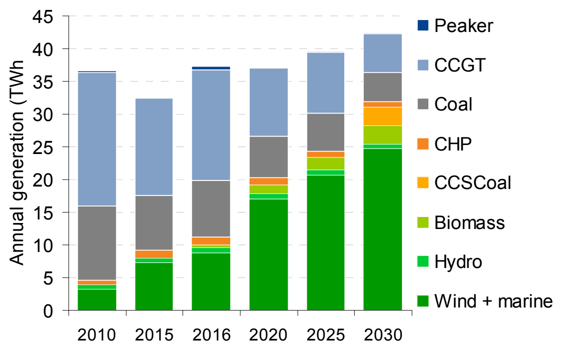
		2010	2015	2016	2020	2025	2030
System cost	Variable	1300	1183	1331	870	796	653
	Fixed	290	348	352	481	558	662
	No-Load	215	194	219	141	128	96
	Starts	21	25	35	23	23	20
EUC	Thermal	2295	2084	2463	1759	1669	1567
	ROCs	14	31	45	128	272	351
	REFIT	25	63	79	179	252	312

C.10.1 Price Responsive Demand Management scenario page 2

GB annual generation



SEM annual generation



GB annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	13.0	34.5	40.8	92.5	115.3	136.4
Hydro	4.7	4.9	4.9	5.3	6.1	6.9
Biomass	9.9	22.5	22.5	22.5	24.4	25.0
Nuclear	60.2	44.5	30.4	47.7	58.7	83.5
CCSCoal	0.0	0.0	0.0	10.5	10.4	20.1
CHP	29.2	34.0	34.9	38.7	43.5	42.9
Coal	132.0	109.1	103.7	81.4	42.7	13.2
CCGT	122.7	116.8	125.2	98.3	86.3	65.0
Peaker	0.0	0.0	0.0	0.0	0.0	0.0
Total	371.7	366.2	362.4	396.9	387.4	392.9

SEM annual generation

TWh	2010	2015	2016	2020	2025	2030
Wind + marine	3.2	7.3	8.8	17.1	20.7	24.7
Hydro	0.8	0.8	0.8	0.8	0.8	0.7
Biomass	0.0	0.0	0.5	1.4	1.9	2.8
CCSCoal	0.0	0.0	0.0	0.0	0.0	2.8
CHP	0.7	1.1	1.1	1.1	1.1	0.8
Coal	11.3	8.4	8.7	6.3	5.7	4.5
CCGT	20.5	14.8	16.9	10.4	9.3	6.0
Peaker	0.2	0.1	0.5	0.1	0.1	0.1
Total	36.6	32.5	37.3	37.1	39.5	42.4

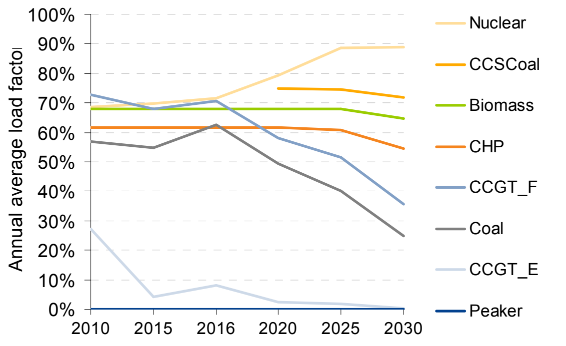
GB annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	3.5%	9.4%	11.3%	23.3%	29.8%	34.7%
Hydro	1.3%	1.3%	1.3%	1.3%	1.6%	1.7%
Biomass	2.7%	6.1%	6.2%	5.7%	6.3%	6.4%
Nuclear	16.2%	12.1%	8.4%	12.0%	15.2%	21.2%
CCSCoal	0.0%	0.0%	0.0%	2.6%	2.7%	5.1%
CHP	7.9%	9.3%	9.6%	9.7%	11.2%	10.9%
Coal	35.5%	29.8%	28.6%	20.5%	11.0%	3.4%
CCGT	33.0%	31.9%	34.5%	24.8%	22.3%	16.5%
Peaker	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RES %	7.4%	16.9%	18.8%	30.3%	37.6%	42.8%

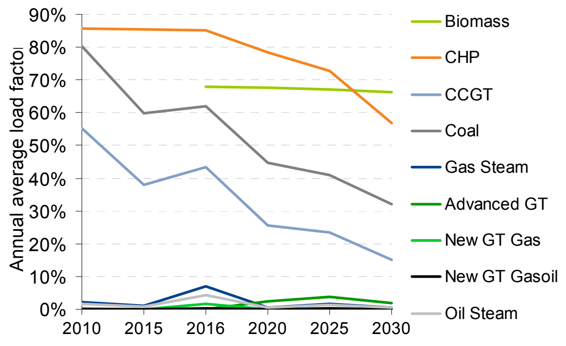
SEM annual generation

% of total	2010	2015	2016	2020	2025	2030
Wind + marine	8.7%	22.3%	23.6%	46.0%	52.3%	58.3%
Hydro	2.2%	2.4%	2.1%	2.1%	1.9%	1.7%
Biomass	0.0%	0.0%	1.2%	3.7%	4.8%	6.6%
CCSCoal	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%
CHP	1.8%	3.5%	3.0%	3.0%	2.7%	2.0%
Coal	30.7%	25.8%	23.3%	16.9%	14.5%	10.5%
CCGT	55.9%	45.7%	45.4%	28.1%	23.5%	14.1%
Peaker	0.6%	0.3%	1.3%	0.2%	0.4%	0.2%
RES %	10.9%	24.8%	27.0%	51.8%	59.0%	66.6%

GB annual average load factor



SEM annual average load factor



GB annual average load factor

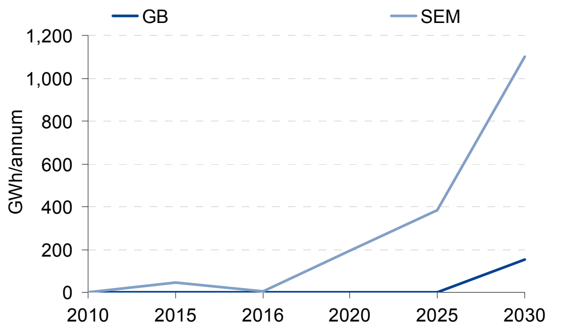
%	2010	2015	2016	2020	2025	2030
Biomass	68%	68%	68%	68%	68%	65%
Nuclear	68%	70%	72%	79%	89%	89%
CCSCoal				75%	75%	72%
CHP	62%	62%	62%	62%	61%	54%
CCGT_E	27%	4%	8%	2%	2%	0%
CCGT_F	73%	68%	71%	58%	52%	36%
Coal	57%	55%	63%	49%	40%	25%
Peaker	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

SEM annual average load factor

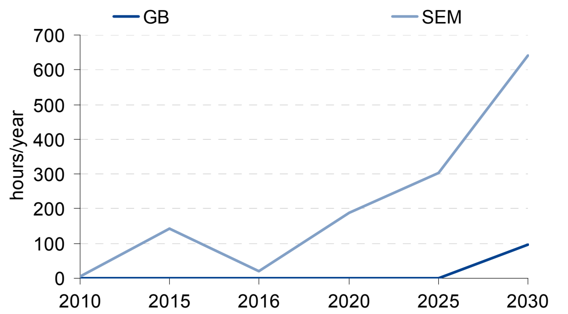
%	2010	2015	2016	2020	2025	2030
Biomass			68%	68%	67%	66%
CCSCoal						73%
CHP	86%	85%	85%	79%	73%	57%
Coal	80%	60%	62%	45%	41%	32%
CCGT	55%	38%	43%	26%	24%	15%
Gas Steam	2%	1%	7%	1%	2%	1%
Advanced GT	<0.1%	<0.1%	<0.1%	2.3%	3.8%	1.9%
New GT Gas	0.2%	<0.1%	1.5%	<0.1%	0.1%	<0.1%
New GT Gasoil	<0.1%	<0.1%	0.3%	<0.1%	0.2%	<0.1%
Oil Steam	1.5%	0.7%	4.2%	0.6%	1.4%	0.5%

C.10.2 Price Responsive Demand Management scenario page 3

Wind curtailment



Shedding periods



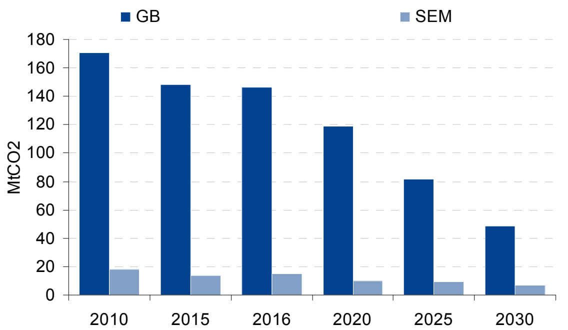
Wind curtailment

GWh/annum	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	0	152
SEM	1	44	4	194	384	1101

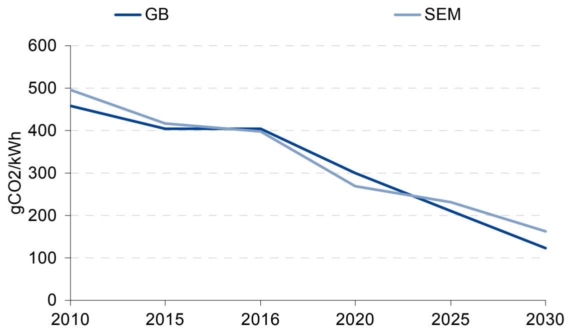
Shedding periods

hours/year	2010	2015	2016	2020	2025	2030
GB	0	0	0	0	0	97
SEM	6	143	20	188	303	641

Carbon emissions



Carbon intensity



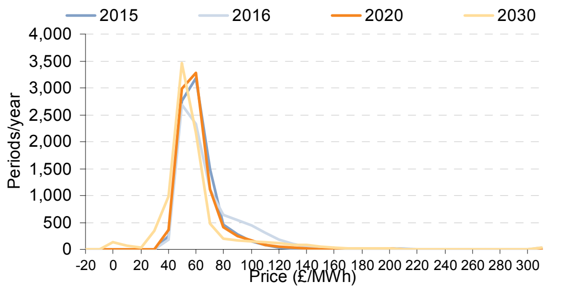
Carbon emissions

MtCO2	2010	2015	2016	2020	2025	2030
GB	171	148	147	119	82	48
SEM	18	14	15	10	9	7

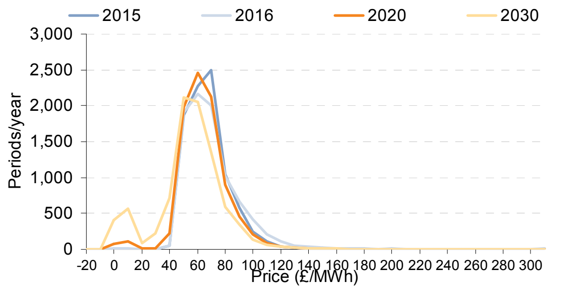
Carbon intensity

gCO2/kWh	2010	2015	2016	2020	2025	2030
GB	459.2	404.4	404.6	300.0	211.1	123.2
SEM	495.9	415.8	397.4	268.7	230.3	162.9

Price distribution (GB)



Price distribution (SEM)



Price distribution (GB)

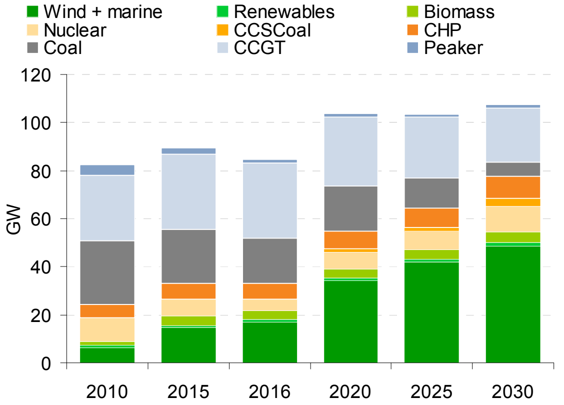
Periods/year	2010	2015	2016	2020	2025	2030
<=0	0	0	0	0	17	132
0-20	0	0	0	1	14	96
20-50	5173	3002	2872	3352	3736	4781
50-100	3481	5559	5068	5192	4524	3145
100-200	101	194	750	207	440	558
>200	6	6	71	9	30	49

Price distribution (SEM)

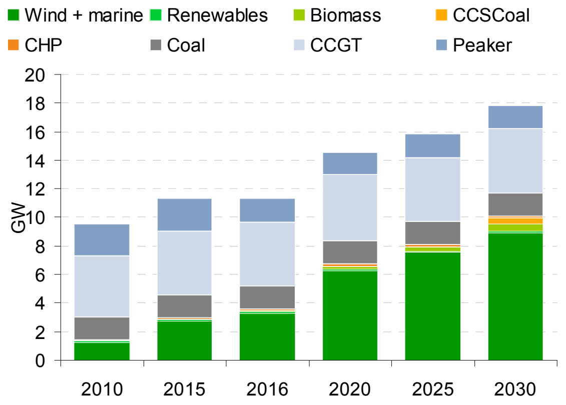
Periods/year	2010	2015	2016	2020	2025	2030
<=0	3	2	10	77	208	404
0-20	0	2	19	135	250	654
20-50	3658	1915	1956	2225	2476	3059
50-100	4994	6632	6269	6138	5584	4469
100-200	99	203	476	177	229	168
>200	6	7	30	9	12	6

C.10.3 Price Responsive Demand Management scenario page 4

Installed capacity (GB)



Installed capacity (SEM)



Intalled capacity (GB)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	6.1	14.5	16.8	34.1	41.8	48.7
Renewables	1.0	1.1	1.1	1.2	1.3	1.5
Biomass	1.7	3.8	3.8	3.8	4.1	4.4
Nuclear	10.0	7.3	4.8	6.9	7.6	10.7
CCSCoal	0.0	0.0	0.0	1.6	1.6	3.2
CHP	5.4	6.3	6.5	7.2	8.2	9.0
Coal	26.6	22.7	18.9	18.9	12.2	6.1
CCGT	27.0	31.2	31.2	28.9	25.4	22.3
Peaker	4.7	2.7	1.7	1.3	1.2	1.4
Total	82.5	89.6	84.8	103.8	103.4	107.3

Installed capacity (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	1.2	2.7	3.3	6.3	7.5	8.9
Renewables	0.1	0.1	0.1	0.1	0.1	0.1
Biomass			0.1	0.2	0.3	0.5
CCSCoal						0.4
CHP	0.1	0.2	0.2	0.2	0.2	0.2
Coal	1.6	1.6	1.6	1.6	1.6	1.6
CCGT	4.2	4.4	4.4	4.6	4.5	4.5
Peaker	2.3	2.3	1.7	1.6	1.7	1.6
Total	9.6	11.3	11.3	14.6	15.9	17.8

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	7%	16%	20%	33%	40%	45%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	2%	4%	4%	4%	4%	4%
Nuclear	12%	8%	6%	7%	7%	10%
CCSCoal	0%	0%	0%	2%	2%	3%
CHP	7%	7%	8%	7%	8%	8%
Coal	32%	25%	22%	18%	12%	6%
CCGT	33%	35%	37%	28%	25%	21%
Peaker	6%	3%	2%	1%	1%	1%

Installed capacity mix (SEM)

GW	2010	2015	2016	2020	2025	2030
Wind + marine	13%	24%	29%	43%	47%	50%
Renewables	1%	1%	1%	1%	1%	1%
Biomass	0%	0%	1%	2%	2%	3%
CCSCoal	0%	0%	0%	0%	0%	2%
CHP	1%	1%	1%	1%	1%	1%
Coal	17%	14%	14%	11%	10%	9%
CCGT	44%	39%	39%	32%	28%	25%
Peaker	24%	20%	15%	11%	10%	9%

Investment cost (GB)

£m	2009	2010	2011	2012	2013	2014
Thermal	2113	1339	1500	1238	391	122
Renewable	4078	21	2997	3973	2997	3973
	2015	2016	2017	2018	2019	2020
Thermal	391	122	122	1666	3858	5362
Renewable	2997	4566	9593	9593	9593	9593
	2021	2022	2023	2024	2025	2026
Thermal	122	122	3858	122	3858	122
Renewable	3570	3570	3570	3570	3570	3395
	2027	2028	2029	2030		
Thermal	5362	2055	4556	740		
Renewable	3395	3395	3395	3395		

Investment cost (SEM)

£m	2009	2010	2011	2012	2013	2014
Thermal	213	789	122	122	122	162
Renewable	21	21	521	1496	521	1496
	2015	2016	2017	2018	2019	2020
Thermal	301	122	170	188	327	170
Renewable	521	684	1022	1022	1022	1022
	2021	2022	2023	2024	2025	2026
Thermal	170	162	122	122	122	968
Renewable	661	661	661	661	661	678
	2027	2028	2029	2030		
Thermal	122	122	122	122		
Renewable	678	678	678	678		

Lost Load

MW	2010	2015	2016	2020	2025	2030
GB	0	0	289	0	323	945
SEM	0	0	0	0	0	0

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ANNEX D – WIND METHODOLOGY

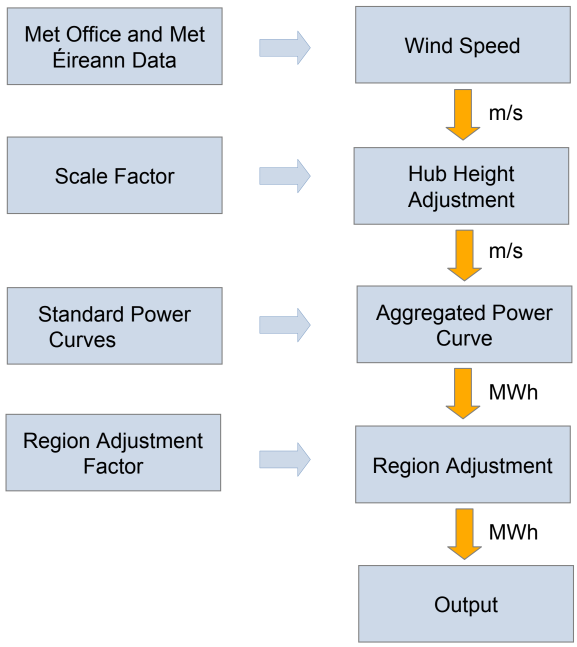
The objective of the wind model is to transform the hourly wind speed data into realistic hourly wind generation profiles for the UK and SEM markets. The scope of the model includes geographical coverage of the two markets under investigation covering wind generation that is envisaged to be deployed in the UK and SEM markets up to 2030. Therefore it is necessary for the model to account for onshore and offshore wind generation that is expected to enter into the markets of GB and SEM.

In order to provide adequate coverage, 27 GB sites have been selected (19 onshore and 8 offshore) while 9 sites were selected for the SEM (8 onshore and 1 offshore). The reasoning for the number of chosen sites and other data assumptions is presented in subsequent sections.

The methodology used for this model has been derived from a review of the available literature, particularly the work carried out under the auspices of the European Trade Wind project, and through dialogue with Founders and Members of the intermittency study.

A flow chart of the model is shown in Figure 6. The following section briefly explains the steps of the methodology:

Figure 6 – Flow diagram of the Pöyry wind model



Source: Pöyry Energy Consulting

1. Hourly wind speed data for the 36 sites for the years 2000-2008 has been used as an input to the wind model.
2. The first stage of the wind model converts the recorded wind speed to hub height wind speed via a scale factor. The scale factor converts the wind speed at Met

mast[24] height to the equivalent at turbine hub height. The terrain scale factor, α, is defined by the local environment of the Met mast.

$$U = U_0 \left(\frac{h}{h_0} \right)^{\alpha}$$

Where

U : *Wind speed at hub height* (m/s)

U_0 : *Wind speed at mast height* (m/s)

h : *Hub height* (m)

h_0 : *Mast height* (m)

α : *Terrain Scale factor*

3. The modified wind speed is then converted to power output via an aggregated power curve. The procedure for deriving the aggregated power curve is detailed in section 1.1.1
4. The regional adjustment factor is derived during the validation process, as a result comparing the model generation profile to recorded data used as a benchmark. As will be shown in the data section, there is more than one wind location per wind region (which is necessary to introduce for purposes of validation). Power output is aggregated to the regional level via a regional adjustment factor

1.1.1 Power curves

The power curve converts the uplifted wind speed into power output. Power curves are provided by wind turbine manufacturers and define the electrical output of a single turbine for a range of wind speeds. Therefore, the generation profile for a single turbine can be simulated by recording the output for a given wind speed at a certain point in time. If wind speed data were on an hourly basis, the hourly generation profile of a single wind turbine could be estimated using this method.

The wind generation profile from a group of turbines covering a dispersed area cannot be represented by a normal power curve. The reason for this is primarily the spatial and temporal distribution of wind over the area covered by the wind farm in question. The cumulative effect of these variations is to smooth the standard power curve. The extent to which smoothing occurs is defined by the characteristics (e.g. physical dimensions, terrain profile) of the area in question. Given the scope of the wind model is to produce hourly generation profiles for the markets in question implies that the smoothing must be taken into account.

The smoothed power curve, also known as the aggregated power curve, represents the cumulative effect of a number of wind turbines dispersed over a given area on the power output profile. The objective of the power curve model is to produce two generic aggregate power curves for use in the wind model; one for onshore sites and one for offshore sites.

The methodology for producing the aggregated power curve is as follows:

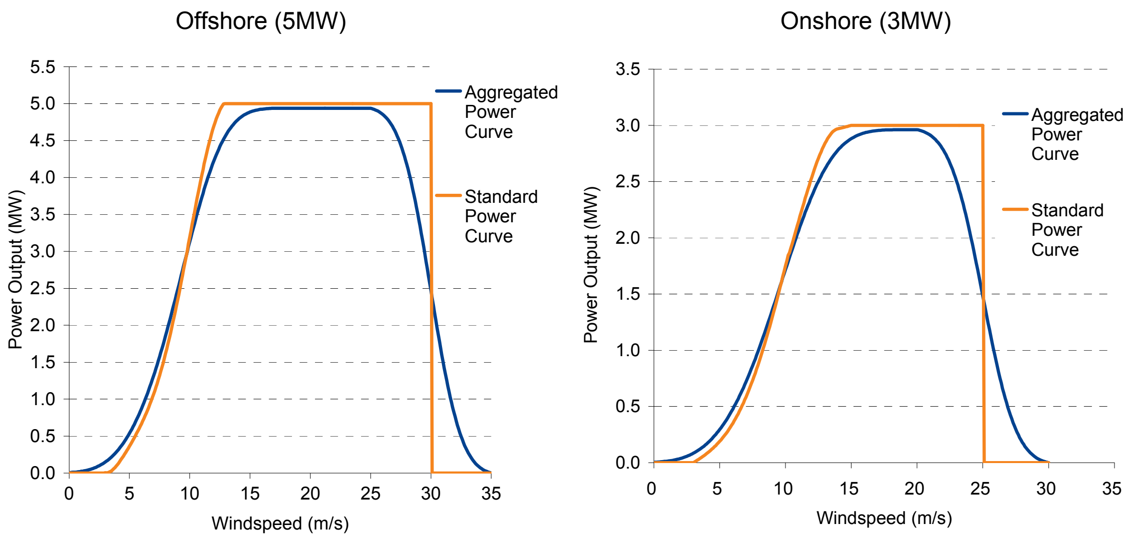
---

24 Met masts are the meteorological masts which measure windspeed, temperature, precipitation and other weather indicators across the UK

1. Convert standard power curve to desired wind speed resolution e.g. wind speed intervals of 0.1m/s
2. Generate probability distribution of wind speeds in the area under investigation
3. Apply probability distribution to wind speed series
4. Create aggregated power curve by mapping modified wind speed to standard power curve

The method was applied to two turbine profiles; a 3MW turbine representing onshore sites and a 5MW turbine representing offshore sites. The two turbine profiles were chosen with input from study Founders. The reason for choosing (a relatively large) 3MW turbine to serve as being representative of onshore sites is to better account for generation at low wind speeds. The offshore turbine of 5MW capacity was selected because offshore sites generally use turbines with the largest technically feasible capacity as a result of the expense involved in the construction of offshore wind farms. Given that this study extends to 2030, it is likely that turbines with a capacity of at least 5MW will be deployed.

Figure 7 – Aggregated power curves

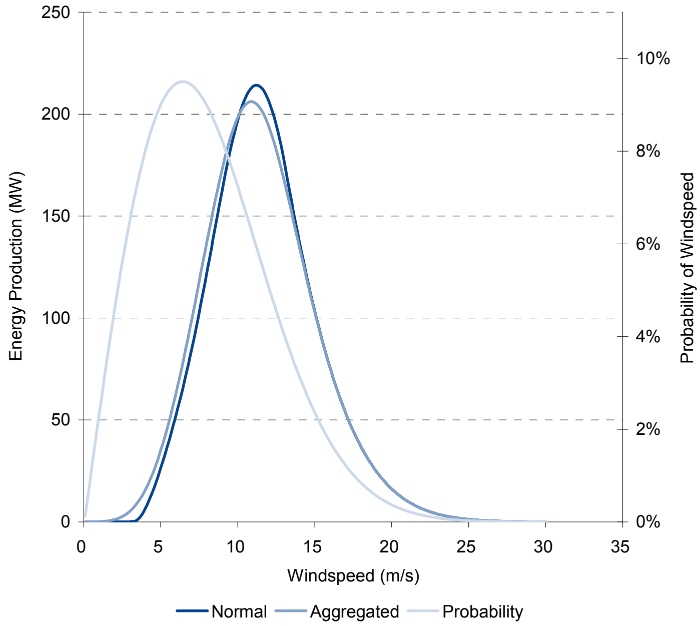


Source: Pöyry Energy Consulting

Figure 7 presents the aggregated power curve in relation to the standard power curve for both offshore and onshore turbines. From inspection of Figure 7, the aggregated power curve registers a power output at lower and higher wind speeds than the standard power curve, but the period of peak generation, corresponding to wind speeds of between 14 m/s and 25 m/s (or 30 m/s for the offshore turbine) in the standard power curve, is shorter in the case of the aggregated power curve.

Validation of the aggregated power curve entails a comparison between the total annual energy output of a hypothetical wind turbine based on the standard power curve profile and the energy output of a hypothetical unit based on the aggregated power curve. In order to simulate power generation for one year, a probability distribution of the annual wind speed is mapped onto the power curve. The parameters of the probability (Weibull) distribution are typical for UK. The probability distribution and power output curves for the aggregated and standard turbines are shown in Figure 8.

Figure 8 – Energy production from normal and aggregated power curve



Source: Pöyry Energy Consulting

The results, in Table 5, show that the aggregated power curves slightly over-estimate the total power production when compared to a standard power curve. This over-estimation is taken into account by the regional adjustment factor introduced in the validation process.

Table 5 – Error in annual energy production between normal and aggregated power curve

	Annual Energy Output (Standard Power Curve) (MWh)	Annual Energy Output (Aggregated Power Curve) (MWh)	Difference
Onshore (3MW)	9671	9911	2.5%
Offshore (5MW)	17214	17606	2.2%

Source: Pöyry Energy Consulting

ANNEX E – MET OFFICE INFORMATION ON CHOICE OF WIND SITES

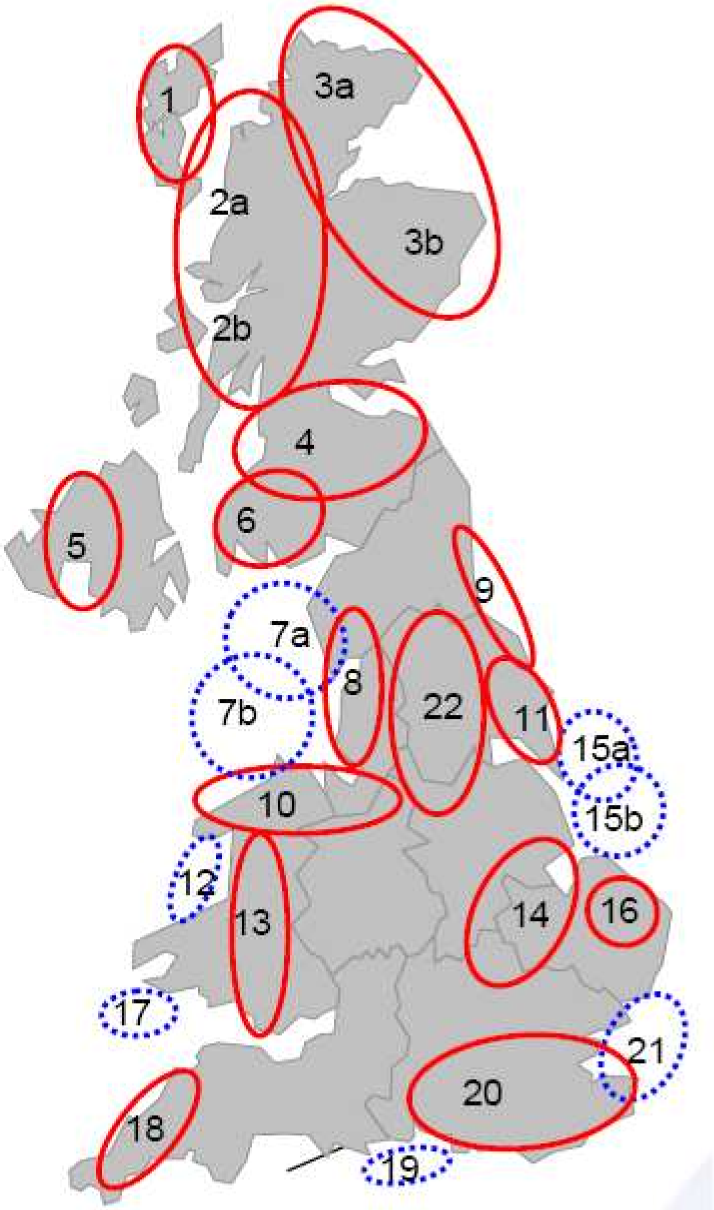
The information in this section has been written and provided by the UK Met office.

E.1 Background

This document supplements the supply of hourly wind speed observations, years 2000-2007, to Pöyry Energy Consulting for the purpose of modelling wind energy generation at potential wind farm sites. The areas of interest are scattered across the whole UK and its coastal waters. Interest also extends to some sea areas far from land but data provision for these areas is being dealt with separately. The areas considered here have been denoted in Figure 1.

Anemometer sites that made hourly wind observations over the period 2000-2007 were chosen to provide the best possible representation of each area, within the constraint of using a maximum of 26 sites. Ultimately it was decided that the 7 areas over sea would be better represented with model-derived wind data than by anemometer data from an adjacent coastline, leaving 19 anemometer stations to represent the land areas. Figures 2(a) and 2(b) show available anemometer sites of possible relevance to the areas of interest shown in Figure 1, with the stations finally chosen labelled in red. This report gives the basis for this selection and a methodology for correcting the data from each anemometer station to represent conditions at a wind turbine anywhere within the attributed numbered zone.

Figure 9 – Potential areas for wind farm locations



Note: Areas 7a and 7b have subsequently been combined into a single area 7.

Figure 10 - Relevant anemometer sites with the final choices in red – UK excluding Northern Ireland

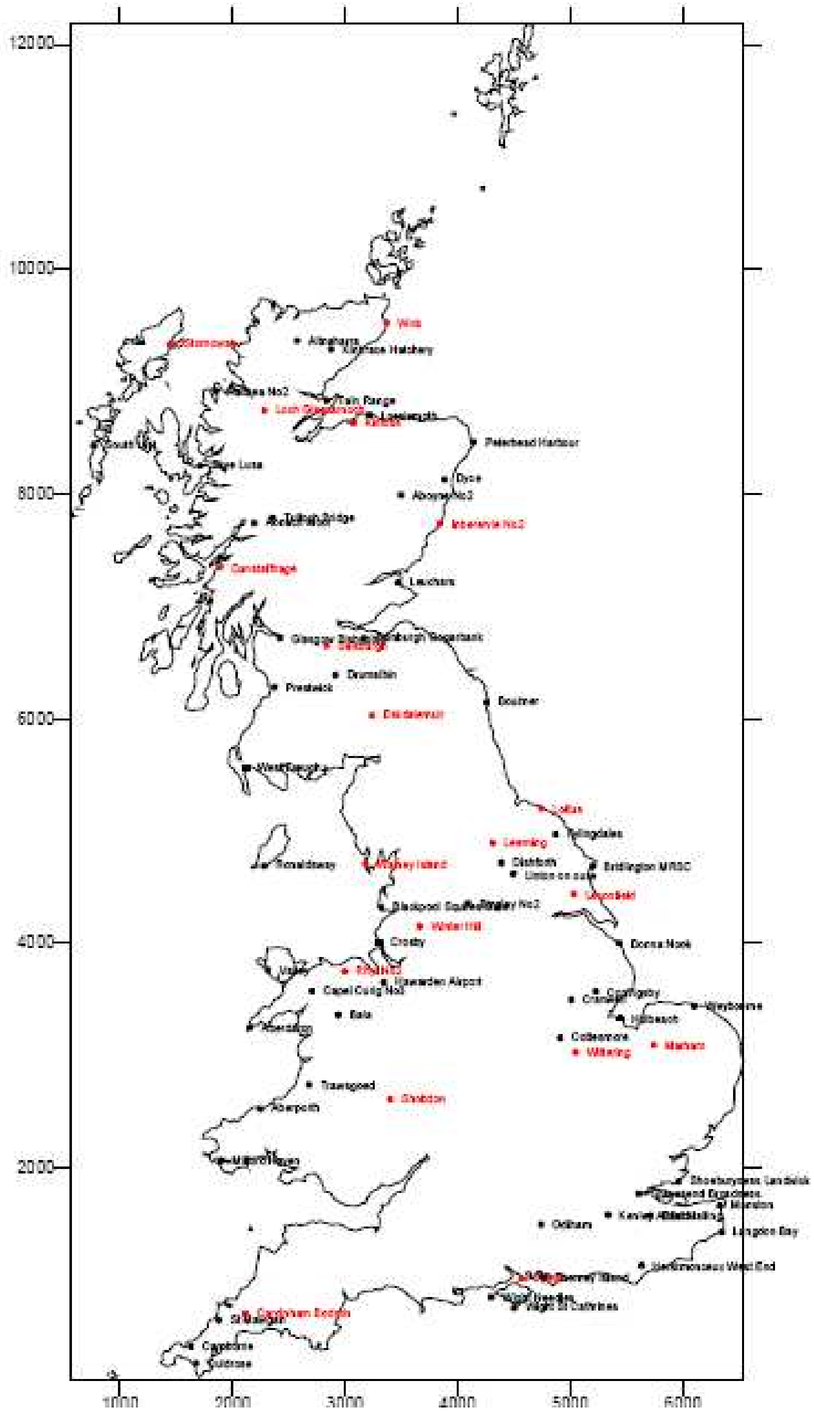
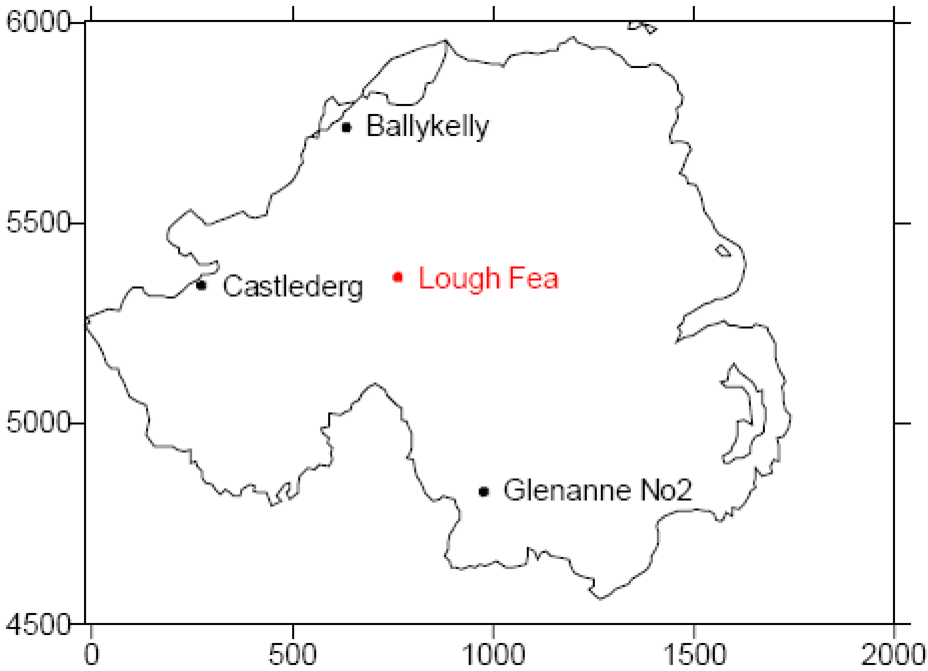


Figure 11 – Relevant anemometer sites with the final choice in red – Northern Ireland



E.2 Factors influencing wind at anemometer and turbine sites

Wind speed is fundamentally governed by atmospheric pressure gradients and, in particular, in the UK, by the degree of proximity to the most frequent track of Atlantic storms north-eastwards between Scotland and Iceland. On this basis, average wind speeds might be expected to be somewhat stronger towards the northwest of the UK. However, in practice, wind speed at a specific location can be greatly modified by a number of other factors. Away from local obstructions, such as adjacent trees or buildings, the most important of these factors are the roughness of the surface over which the wind blows, the topographical setting of the location and the gradual increase in mean wind speed with site altitude. An additional consideration is height above ground (or sea) surface, as wind speed decreases from about 600m height towards the surface – the rate of decrease being greatest near the surface and a function of surface roughness.

E.2.1 Influence of large-scale topography

The influence of topography on wind speed (and direction) is on both large and small spatial scales. Examples of large scale topographic influences would be the funnelling of west-south-westerly winds through the Central Lowlands of Scotland and the sheltering of the same land corridor from northerly and southerly winds by the Scottish Highlands and Southern Uplands. In the context of this report, 'large scale topography' is taken to mean features of horizontal extent similar to, or greater than, the sizes of the areas of interest marked in Figure 1. In choosing the anemometer sites for this project, the aim has been for each site to represent a large-scale topographic zone.

E.2.2 Influence of small-scale topography

Wind speed is also modified by smaller-scale hills, hollows, ridges and valleys so that, in the vicinity of such features, additional topographic influence on wind speed will remain. To a greater or lesser extent, depending on atmospheric conditions, the atmosphere behaves as if it had a rigid ceiling. Thus, hills and valleys represent constrictions to the wind flow between the surface and this ceiling, causing acceleration at the point of constriction – i.e. over the hill or ridge summit. However this is an extremely simplistic model and real influences of topography are very complex. For instance, for an isolated hill, the wind may preferentially blow around the sides of the hill rather than over the summit. Also, the impact of topography will usually be different for different wind directions, so that systematic estimation of the net impact of topography over all wind directions is a major yet uncertain undertaking and is not attempted here. Deep valleys are particularly difficult to assess and, according to wind direction, may act as funnels or be cut off from the main wind flow. Many, but by no means all, of the chosen anemometer sites are in flat terrain where significant small scale topographic influences are unlikely. Attention is drawn to anemometer sites for which there should be an awareness of possible small scale topographic influences. It should be kept in mind that some of the turbine sites may also be subject to small scale topographic influences not represented by the chosen anemometer station.

E.2.3 Influence of terrain (and sea) roughness

Within about 600m of the land or sea surface, the wind speed which would occur in free air is reduced by friction over the surface, the retarding effect increasing as the surface is approached. For this reason, wind speeds increase with height above ground or sea. The degree of retardation towards the surface is dependant upon surface roughness and some impact of surface roughness is derived from up to several tens of kilometres upwind; however typically well over 50% of the influence is from within 1-2 kilometres of the site. Except in storm conditions, sea surfaces are the smoothest and cause the least resistance to wind flow. Next come bare, flat land surfaces, followed by increasingly rough surfaces as the proportion of land covered by trees, buildings and windbreaks increases, the 'roughest' surfaces being the intensely built-up areas of city centres. On this basis, Cook (1885) defined six surface roughness categories (0-5) and provided descriptive definitions of each as follows. This reference also provides a photographic illustration of each category.

Terrain roughness category 0: Large expanses of water, mudflats, snow-covered farmland, large areas of flat tarmac.

Terrain roughness category 1: Flat grassland, parkland or bare soil, without hedges and with very few isolated obstructions.

Terrain roughness category 2: The meteorological standard: Typical UK farmland with nearly flat or gently undulating countryside, fields, crops, fences or low boundary hedges and a few trees.

Terrain roughness category 3: Farmland with frequent high boundary hedges, occasional small farm structures, houses or trees.

Terrain roughness category 4: Dense woodland or domestic housing typically between 10% and 20% plan area density.

Terrain roughness category 5: City centres comprising mostly 4-storey buildings or higher, typically between 30% and 50% plan area density.

Using maps and photographs, a terrain roughness category has been assigned to each anemometer site. This could not be a high-precision exercise, especially at sites (typical of coasts) with marked differences in surface roughness trajectory according to wind direction. In such cases, a biased average was estimated, giving greater weight to terrain roughness towards the south-westerly direction quarter as winds blow more frequently from this quarter at most UK sites. The terrain category allocated to each anemometer site is listed in the 4th column of Annex A. In practice, all sites had an overall terrain roughness category between 0 and 3 with no cases of 4 or 5. It is assumed that the criteria for choice of wind turbine sites will also rule out consideration of terrain categories 4 and 5.

E.2.4 Influence of anemometer or turbine height above surface

The conventional height for meteorological anemometer cups is 10m above the ground. At a few locations the cups are at a non-standard height but their speeds can be corrected to the standard 10m height. Column 5 of Annex A gives a height for each anemometer. In practise, because the rate of increase in wind speed with height above ground varies with surface roughness, it is useful to combine the two effects to obtain an overall terrain roughness – anemometer height correction for each site. Table 9.4 of Cook (1985) gives such combined factors for the specific case of converting wind speeds from any terrain category and height above surface to 10m above terrain category 2 (the meteorological standard). However, from this table, conversions between any other terrain category/anemometer height pair can be deduced. Using this table and the terrain category and height attributed to each anemometer, a series of division factors has been derived to convert wind speeds from each anemometer to wind speeds at 10m above any other terrain category 0, 1, 2 or 3. These division factors are given in columns 6-9 of Annex A.

E.2.5 Influence of altitude above sea level

Altitude over the site above mean sea level should not be confused with the height of the anemometer or turbine above the ground or sea and considered in Section 2.4. On average, wind increases gradually with altitude of site above mean sea level. According to Cook (1985), the rate of increase varies with wind speed but is typically (1+0.0007) of the basic wind speed for each metre above mean sea level. On this basis, column 10 of Annex A gives division factors to correct winds speeds from the altitude of each anemometer site to sea level. Obviously many wind turbine sites will not be at sea level, but knowledge of this correction allows standardisation of all data to a common altitude (mean sea level) for comparison purposes and also, potentially, as a prior step to further correcting the data to the attitude of a wind turbine site. In columns 11-14 of Annex A, the altitude factor for each anemometer site is combined with the corresponding terrain/anemometer height corrections from columns 6-9 to provide a set of division factors for standardising the wind data from each anemometer site to 10 m above sea level over any terrain type 0, 1, 2 or 3.

E.3 Application of wind speed scaling factors

The simplest, but crudest, way to use the supplied wind data would be to choose the most representative anemometer site and use the data from that site without any correction. Given the likely spatial variations within an area, as discussed in Section 2, the allocated anemometer site will often represent a specific turbine site only very crudely. The following method would improve upon using the data without modification:

(i) Choose the most representative available anemograph site – usually the one (or one of the two or three) attributed to the area in which the turbine is located (see Figures 2(a) and 2(b)).

(ii) Assess the terrain category of the turbine site according to the criteria given in Section 2.3. Reference to example photographs in Cook (1985) might aid this assessment.

(iii) For the chosen anemometer site, obtain the correction factor for that turbine terrain type from columns 11, 12, 13 or 14 of Annex A and divide all wind speeds by this factor to obtain equivalent turbine site wind speeds standardised to 10m height and sea level altitude.

(iv) Correct the resulting wind speeds to the altitude above mean sea level of the turbine site by adding 0.07% to the wind speed for every metre altitude (see Section 2.4).

(v) Correct to the height (above ground or sea) of the turbine by multiplying by the factor for the appropriate terrain category and height in Annex B. Annex B has been derived from Table 9.4 of Cook (1985).

E.4 Comments on the chosen anemometer sites

The following brief notes are offered regarding the chosen anemometer sites. The numbered areas refer to those denoted on the map at Figure 1. The location of each anemometer site is illustrated by the maps at Figures 2(a) and 2(b), with the chosen anemometer sites labelled in red.

<u>Area 1 – Hebrides. Chosen site: Stornoway.</u>

The available choice was between two sites, the other, South Uist, being on the south-west side of the islands and so even more exposed to Atlantic storms. Stornoway, on the slightly less exposed north-east side of the islands, was chosen as more generally representative and because the potential wind farm sites currently being considered are close to Stornoway. Nonetheless, the anemometer is on a well exposed, flat, open airfield, with sea only 300 metres to the north-north-east.

It is also recommended that Stornoway be used for any coastal, turbine sites in Area 2(a) – the northern half of Area 2, including Skye – see below.

<u>Area 2 – Northwest Scotland. Chosen sites: Stornoway, Loch Glascarnoch and Dunstaffnage.</u>

This is a large area of complex terrain, encompassing a wide range of exposures. The Dunstaffnage site, though coastal, is also quite land-locked – being in the Firth of Lorne, rather than adjacent to open sea. It is also in a relatively sheltered, northeast-facing bay, rather than having direct sea exposure to the south-west. Much of the land from east through to south-south-west of the anemometer is forested. For these reasons the site has been attributed a relatively high terrain roughness category (see column 4 of Annex A). Although it has been chosen as the nearest anemometer to several potential turbine sites, it is particularly important in this case that a correction procedure, such as that documented in Section 3, is applied to the data. For any sites on Skye or the more directly exposed mainland coastline northwards from Mull, use of the Stornoway data would be more appropriate, even though, strictly, Stornoway is in Area 1.

Loch Glascarnoch has been chosen in an attempt to represent inland upland (but not mountain-top) sites in the Scottish Highlands, whether in Area 2 or Area 3. It is situated near the border between these two areas, in bare but hummocky terrain, 265m above mean sea level. The site is near the summit (watershed divide) of two valleys, together forming a west-north-west to east-south-east land corridor; nonetheless, in all other directions the site is surrounded by higher ground. When considering both Loch Glascarnoch and potential turbine sites in the Highlands, it must be appreciated that there will be huge spatial variations in small-scale topographic influences on wind flow in this complex terrain. The choice of Loch Glascarnoch merely caters for the large scale topographic influence of the Highlands, as a whole, possibly acting as an obstruction around which winds, to some extent, may be deflected. The topographic exposure of Loch Glascarnoch is unlikely to be representative of high mountain summits, even after correction, because of the difference in small-scale topographic context. For the purpose of anemometer site selection it has been assumed that none of the proposed turbine sites are on high mountain summits (say, above 1000m altitude). In such a case, Met Office advice should be sought.

Area 3 – Northeast Scotland. Chosen sites: Wick, Kinloss, Inverbervie and Loch Glascarnoch.

Loch Glascarnoch is near the border between Area 3 and Area 2 and is intended to represent inland upland portions of both zones. See Area 2 for greater comment. Wick, Kinloss and Inverbervie are all near-coastal but represent coastlines of different aspect.

Wick represents the promontory of the far north-east of Scotland and probably is the best representation for the similarly-shaped promontory around Peterhead.

Converging towards Inverness from either of these promontories, increasing topographic shelter by Scottish Highlands seems likely. In particular, the north-facing coastline eastwards from Inverness (represented by Kinloss) lies in the lee of the Cairngorms as far as the prevailing south westerly winds are concerned and so might be expected to be somewhat less windy.

The east-south-east-facing coastline southwards of Peterhead, through Aberdeen, towards the Firth of Fife is represented by Inverbervie and may have different characteristics again. Although having high ground to the west, this coastline is exposed to the south and south-south-west and also (especially towards its southern end) lies almost in line with the land corridor of the Central Lowlands through which the prevailing west-south-westerly winds funnel. It should, however, be borne in mind that the Inverbervie anemometer is on a coastal hilltop and therefore particularly exposed.

Area 4: Central Lowlands of Scotland. Chosen site: Drumalbin.

Although termed ‘Central Lowlands’, this broad west-south-west to east-north-east corridor of land from, roughly, Glasgow to Edinburgh to Dundee, contains several clumps of hills – and these are assumed to be the more likely sites for wind turbines. Hence, the chosen anemometer site of Drumalbin is at the relatively high altitude of 245m, albeit better described as being on undulating plateau rather than a hill top. The Central lowlands of Scotland may be considered as a very distinct large-scale topographical zone in terms of wind climatology – channelling and funnelling winds from the (prevailing) west/southwest and from the east/northeast, while being sheltered from northerly and southerly winds.

Area 5: Northern Ireland. Chosen site: Lough Fea.

At 225m altitude this is the highest available site; however, its exposure is not particularly high, the site being in a broad high-level valley with some trees – probably best described as category 3 terrain roughness apart from a fetch across a small lake to the west and southwest . For the latter reason, an overall category 2 has been attributed.

Area 6: Southern Uplands of Scotland. Chosen West Freugh (but also Drumalbin and Boulmer)

The area numbered 6 in Figure 1 is somewhat misleading, as the south-eastern sector of the area numbered '4' (Central Lowlands), as marked, actually covers the eastern side of the Southern Uplands. The southern edge of the Central Lowlands, along with the Southern Uplands, contains a broad west-east swath of potential turbine sites – some being on the west or south coasts, some being east-coastal and many being inland.

West Freugh is intended to represent lowland sites towards the west of the area and, in particular, sites within a few kilometres of the west or south coasts. Lowland sites towards the east of the Southern Uplands, and in particular those within a few kilometres of the North Sea coast would be better represented by Boulmer (area 7). Inland upland areas would be better represented by Drumalbin on the edge of Area 4.

Area 8: Lancashire. Chosen sites: Walney Island and Winter Hill.

Walney Island is a low-lying but very exposed location and is intended to represent the Lancashire coastline. The inclusion of Winter Hill is to cater for any wind farms on top of the Pennines. This site is by far the highest-altitude site in the list, being on top of an exposed 440m summit north-west of Manchester.

Area 9: North-east England. Chosen site: Boulmer.

Coastal Boulmer best represents east-coastal locations, whether in Northeast England or Southeast Scotland. However correction to a higher terrain roughness category should also enable it to give a reasonable representation of inland sites.

Area 10: North Wales. Chosen site: Rhyl.

Like the Scottish Highlands, the complex, often hilly or mountainous terrain of Wales is particularly difficult to represent by available anemometer sites. Although Rhyl is known as a coastal resort, its anemometer site is actually several kilometres inland in category 3 terrain. Also being on a north-facing slope, the site may be afforded some additional shelter from the prevailing south-westerly wind direction. Nonetheless it is probably the best available representation of non-coastal sites in North Wales, provided appropriate corrections are made for differences in terrain roughness and altitude and provided it is not used to represent a high mountain-top. Should the latter be necessary, use of modelled data for area 7 and/or 12 is recommended, still following the correction procedure documented in Section 3. For north-coastline sites, particular care should be taken to apply a lower terrain roughness category – probably terrain category 1 as a compromise between open sea to the north and land to the south. Given that this coastline faces away from the prevailing south-westerly wind flow, and lies in the lee of high ground to the south, some reduction in mean wind speed relative to many other coastlines nonetheless seems likely. An alternative way of treating turbine sites on, or just offshore from, the North Wales shoreline might be to interpolate between the Rhyl data and the modelled data for Area 7 (and which represents conditions well off-shore). Note that Anglesey has a much greater exposure to the south-west, and for potential turbine sites on Anglesey it would be more appropriate to use the modelled Area 7 data, correcting it from category 0 terrain roughness to category 1.

Area 11: East Yorkshire/Humberside. Chosen site Bridlington Coastguard.

Bridlington was chosen because of the rather sheltered exposure of Leconfield and because some of the potential turbine sites are coastal. However, although the site is on a low cliff top, very exposed to winds from north-east through to south, the housing estates of Bridlington lie nearby to the west and south-west. As this is the most frequent wind direction, the overall terrain category for the site has been assessed as 2. For most rural sites along the coastline a correction to category 1 would be appropriate. The attributed anemometer height of 15m is actually a compromise between its height above the land surface and its height above the sea surface (at the foot of the shallow cliff).

Area 13: Central Wales. Chosen site: Trawsgoed.

This area has proved the most difficult of all to represent, given the sparse anemometer network and a valley-location of all stations with sufficient record. The selected site of Trawsgoed is no exception, lying in a northwest-southeast aligned valley, otherwise surrounded by hills. Local valley effects may well apply and would be very difficult to assess. The best guidance is probably that Trawsgoed should represent similar topographic locations but should be used with caution, as the correction factors given here in Annex A take no account of any additional small-scale topographic influences. For hill-top or high plateau sites in Central Wales, it would be wiser to use the offshore modelled data for area 12, applying an appropriate terrain category and altitude correction.

Areas 14 and 16 : The Fens and Norfolk. Chosen site: Wittering

This is a straight-forward choice of a flat, well-exposed anemometer site to represent a very flat area. Being an airfield and on top of a very shallow hill (in Fenland terms), the site errs on the side of particularly good exposure and is attributed terrain category 1. This terrain category may not necessarily apply to all potential turbine sites in Areas 14 and 16, depending on the proportion of adjacent woodland.

Area 18: Cornwall. Chosen site: Cardinham

Cardinham is an inland site with category 2 terrain, but on top of Bodmin Moor. For coastal turbine sites apply an altitude correction but also a lower terrain roughness of 1 – or even 0-1 towards the far west of Cornwall.

Area 20: Southeast England. Chosen site: Solent.

It has been assumed, here, that turbines sites in south-east England are most likely to be on the downs or the south coast. The Solent site is almost on the shoreline at Lee on Solent, very exposed to prevailing wind directions north-west, through south-west, to south east. The terrain immediately inland from the site is urban; hence the non-standard anemometer height (see Annex A) in order to rise well above building heights. Given that winds blow predominantly from the open water here, the adjacent urban area is unlikely to greatly reduce wind speeds overall – hence the attributed overall terrain category of 1. However, if comparing these data with data from other sites, it is important that speeds be reduced to take account of the 25-metre anemometer mast.

Area 22: Inland Yorkshire. Chosen site: Leeming.

Leeming is at the northern end of the Vale of York and represents the lowland east of the Pennines. Under certain, very occasional, atmospheric conditions, this area can experience particularly strong westerly winds, but overall, the large-scale topographic condition is one of relative shelter, both by the Pennines to the west and the North Yorkshire Moors and Yorkshire/Lincolnshire Wolds to the east. Leeming is not at all representative of any hill-top Pennine sites and for these, Winter Hill (see Area 8) should be used, making appropriate altitude correction.

Areas 7, 12, 15(a), 15(b), 17, 19 and 21: Use model-derived data for central point.

These data are derived from the Met Office's numerical atmospheric model and represent wind speeds 10m above open water (i.e. category 0 'terrain roughness).

E.5 Anemometer starting speeds

Most anemometers installed by the Met Office have 'cups' that have to be turned, mechanically, by the wind in order to register a wind speed. Once the cups are turning, the recorded wind speed is proportional to the speed of rotation of the cups; however, in order for the cups to start turning, a static frictional force has to be overcome. This means that, when the wind increases from calm, a finite wind speed has to be reached before the cups start to turn; meanwhile 'calm' continues to be registered. Once the cups are turning they will carry on turning at lower wind speeds than the starting threshold, although there is still a finite 'stall' speed below which the cups will cease to turn.

As instrumentation has improved, so also has the mobility of anemometer cups, so that there is no single start speed that can be applied uniformly across the anemometer network. During the period of data provision, two types of anemometer were in use at the requested sites – the Mark 4 and the Mark 6, the latter having a significantly lower starting speed. For these two anemometer types, average start and stall speeds are as follows:

- Mark 4: Start speed 3 ±1 m/s; stall speed 1 m/s – based on a tested sample of 71 anemometers;
- Mark 6: Start and stall speed 0.5 m/s – based on a tested sample of about 250 anemometers.

The main impact on recorded wind speeds applies to the Mark 4 only and is during sustained periods of light winds <3 m/s, during which the anemometer may record 'calm' throughout. It may be useful to consider this in the context that most wind turbines also have a 'cut-in' speed, though the precise details of the turbines to be used in this case are not known. Annex C lists the type(s) of anemometer in use at each site during the period of data provision.

E.6 References

Cook, NJ (1985): The designer's guide to wind loading of building structures, Part 1: Background, damage survey, wind data and structural classification'; Building Research Establishment, Butterworths.

E.7 Addendum A – Anemometer site details with terrain categories and standardisation factors

At step (iii) of Section 3, wind speeds from the chosen anemometer site are divided by the appropriate factor from one of the last four columns of this table, according to the terrain roughness category of the turbine site. The resulting wind speed is the speed which would occur at the turbine if it were mounted 10m above a sea-level site of this terrain category. Step (iv) of Section 3 then corrects this speed to the actual altitude above mean sea level of the turbine site and step (v) of Section 3 corrects to the actual height above ground (or sea) surface of the turbine (see Annex B).

Area	Station	Alt.	Terrain Cat.	Anemo ht.	Combined terrain/anemo. ht division factors to 10m:				Alt. div. factor	Final division factors to 10m above flat, sea level:			
		(m)	(Cook(1985))	(m)	to Cat 0	to Cat 1	to Cat 2	to Cat 3	to sea level	to Cat 0	to Cat 1	to Cat 2	to Cat 3
1	Stornoway	2-15	1	10	0.91	1	1.11	1.29	1.006	1.09	0.99	0.90	0.77
2	Loch Glascarnoch	265	2	10	0.82	0.9	1	1.16	1.186	1.03	0.94	0.84	0.73
2	Dunstaffnage	3	3	10	0.7	0.77	0.86	1	1.002	1.43	1.30	1.16	1.00
3	Wick	36	1	10	0.91	1	1.11	1.29	1.025	1.07	0.98	0.88	0.76
3	Kinloss	5	2	10	0.82	0.9	1	1.16	1.004	1.22	1.11	1.00	0.86
3	Inberbervie No2	134	1	10	0.91	1	1.11	1.29	1.094	1.00	0.91	0.82	0.71
4	Drumalbin	245	2	10	0.82	0.9	1	1.16	1.172	1.04	0.95	0.85	0.74
5	Lough Fea	225	2	10	0.82	0.9	1	1.16	1.158	1.05	0.96	0.86	0.74
6	West Freugh	11	1	10	0.91	1	1.11	1.29	1.008	1.09	0.99	0.89	0.77
7	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
8	Walney Island	15	0-1	10	0.95	1.05	1.16	1.35	1.011	1.04	0.94	0.85	0.73
8	Winter Hill	440	1	10	0.91	1	1.11	1.29	1.308	0.84	0.76	0.69	0.59
9	Boulmer	23	1	10	0.91	1	1.11	1.29	1.016	1.08	0.98	0.89	0.76
10	Rhyl No2	77	3	10	0.7	0.77	0.86	1	1.054	1.36	1.23	1.10	0.95
11	Bridlington MRSC	15	2	15	0.82	0.9	1.08	1.16	1.011	1.21	1.10	0.92	0.85
12	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
13	Trawsgoed	63	3	10	0.7	0.77	0.86	1	1.044	1.37	1.24	1.11	0.96
14 (& 16)	Wittering	73	1	10	0.91	1	1.11	1.29	1.051	1.05	0.95	0.86	0.74
15a	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
15b	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
17	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
18	Cardinham Bodmin	200	2	10	0.82	0.9	1	1.16	1.140	1.07	0.97	0.88	0.76
19	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
20	Solent	9	1	25	0.91	1	1.27	1.29	1.006	1.09	0.99	0.78	0.77
21	Model Data	0	0	10	1	1.1	1.22	1.42	1.000	1.00	0.91	0.82	0.70
22	Leeming	32	2	10	0.82	0.9	1	1.16	1.022	1.19	1.09	0.98	0.84

E.8 Addendum B – Corrections for height of turbine

Turbine height' refers to the height of the turbine above the ground or sea surface. These multiplication factors are to be applied at step (v) of Section 3 and are dependant upon the terrain category of the turbine site. They have been derived from Table 9.4 of Cook (1985). Correction for altitude of the turbine site above mean sea level is made at the previous step (iv) of Section 3.

Turbine height (m)	**Cat 0**	**Cat 1**	**Cat 2**	**Cat 3**
10	1.00	1.00	1.00	1.00
15	1.05	1.06	1.08	1.09
20	1.08	1.11	1.13	1.16
25	1.11	1.14	1.17	1.21
30	1.14	1.17	1.20	1.26
35	1.16	1.19	1.23	1.29
40	1.17	1.22	1.25	1.33
50	1.20	1.25	1.30	1.37
60	1.23	1.28	1.33	1.42
70	1.25	1.31	1.36	1.45
80	1.27	1.32	1.39	1.49
90	1.29	1.35	1.41	1.52
100	1.30	1.37	1.44	1.55

E.9 Addendum C – Type(s) of anemometer at each station during the period of data provision

Station	Anemo Type
Stornoway	MK4 2000 to Aug 2002, MK6 Aug 2002 onwards
Loch Glascarnoch	MK4
Dunstaffnage	MK6
Wick	MK6
Kinloss	MK4 2000 to Mar 2001, MK6 Mar 2001 onwards
Inberbervie No2	MK4
Drumalbin	MK4
Lough Fea	MK6
West Freugh	MK4
Walney Island	MK4
Winter Hill	MK6
Boulmer	MK6
Rhyl No2	MK4
Bridlington	MK6
Trawsgoed	MK4
Wittering	MK4 2000 to Jun 2001, MK6 Jun 2001 onwards
Cardinham	MK4
Solent	MK4
Leeming	MK4

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