Decarbonising the GB power sector: evaluating investment pathways, generation patterns and emissions through to 2030

A Report to the Committee on Climate Change, September 2009

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Executive summary

The Great Britain (GB) electricity market lies on the verge of a major transformation. To meet the country's target of reducing domestic carbon dioxide emissions by 80 percent from 1990 levels, it is likely that the electricity sector will need to be almost fully de-carbonised by 2050. We have already started on the path to that goal, but a much more substantive change will be needed over the next 20 years. By 2030, over 70 percent of generation will need to come from low carbon technologies, up from around a quarter today. It is becoming increasingly clear that no single technology provides the complete answer, and renewables, nuclear and, if proven, carbon capture and storage (CCS) will make significant contributions.

The Committee on Climate Change (CCC) commissioned Redpoint to analyse the investment pathways to 2030 that lead towards decarbonisation of the power sector. As well as understanding the emissions impact of a changing generation mix, the CCC is interested to understand whether the current market design can support these challenging climate goals whilst providing appropriate investment signals, and without compromising security of supply.

We have developed a forward-looking scenario, termed 'Environmentally Favourable Conditions' (EFC), incorporating assumptions that favour successful decarbonisation. These include demand reduction through energy efficiency measures, policies to supply 32 percent of electricity demand in 2020 from renewable sources, and strongly rising carbon prices[1] after 2020. For the EFC scenario we assume that investors make timely investment decisions based on their prevailing cost of capital, with reasonable foresight on the developing demand / supply balance, and with an expectation of rising carbon prices.

However, the future is of course uncertain, and we have also analysed a large number of sensitivities around the EFC scenario to explore the impact on the aspiration of decarbonising the energy sector by 2050. The sensitivities include changes in Government policy, alternative commodity price assumptions, and different investor behaviours. We have used these to inform an understanding of the potential impact of each of these on carbon reduction and security of supply.

Under the favourable assumptions of the EFC scenario, our modelling indicates that a level of decarbonisation can be achieved by 2030 consistent with the 2050 pathway without undue impact on security of supply, albeit at a higher cost for consumers. However, our sensitivities show that there are a range of outcomes in which this may be jeopardised. The carbon price was the single most important factor. In cases where either the carbon price did not rise to the same extent, or where investors did not believe that it would, investment in the low carbon technologies such as nuclear and renewables was reduced relative to the EFC scenario. The assumptions on investor behaviour are also significant. In the sensitivities where investors' perception of risk is higher, investment is slower, with lower investment in higher capital cost, low carbon, technologies.

The analysis demonstrates that the profile of prices and the operation of the system will change significantly with increasing amounts of low marginal cost plant on the system. With large volumes of inflexible or non-dispatchable generation, the risk of spill (when supply exceeds demand) increases. There could be periods where prices fall to zero, or indeed turn negative as renewables bid into the market based on the opportunity costs of lost Renewable Obligation Certificates as compensation for not generating. Sufficiently strong signals for continued investment in this environment may be maintained in part through very high price spikes for short periods when renewables output is low and the system is tight and, in the EFC scenario, through the impact of a higher carbon price. However, towards 2030, the level of low carbon plant on the system is sufficient to begin to disconnect the power price from the carbon price, and

[1] EUA prices are approximately 40 €/tonne in 2020, rising to 120 €/tonne by 2030, and continuing upwards to over 155 €/tonne in 2037.

an open question remains as to how the right investment signals will be set for the final stage of decarbonisation to 2050.

The variability of wind output is also likely to have a large impact on the operating regimes for thermal plant, and on system balancing. The analysis suggests that by 2030 over 20 GW of thermal plant could be operating at a load factor of 10 percent or less. Output from conventional plant may need to swing from close to zero to more than 30 GW within just a few hours by the time generation from renewables reaches 36 percent of the total, which occurs in 2030 in the EFC scenario.

All of this suggests an increasing requirement for the provision of flexibility from both the demand and supply sides. An increased requirement to part-load thermal plant (running at lower efficiency) may be detrimental to carbon dioxide emissions, as would the constraining off of renewables plant if the remaining thermal fleet cannot provide sufficient flexibility. Demand side response could play a very important role in providing flexibility and responsiveness, and with less negative impact on emissions. The technology to support a much more dynamic interaction between demand and supply – starting with the roll-out of smart meters – will play an increasingly important role, and is a key area for further policy development.

Under current market arrangements, investors make decisions, and take associated risks, based on market price signals. There is no evidence that this should not provide an adequate level of security of supply under normal circumstances. However, the demands of meeting very challenging environmental targets in a short timeframe, and the associated need for significant intervention, may present uncertainties that are harder for the market to handle efficiently. Measures to address this could include providing greater certainty with regard to future carbon prices, mechanisms to improve transparency and price signals, approaches that improve the efficiency of dispatch, and strengthening the signals to invest in flexibility on the supply and demand sides.

The sensitivities in this study show a wide range of outcomes for carbon dioxide emissions and security of supply to 2030. Under favourable conditions there is no reason to believe that current market arrangements, combined with existing support for higher cost low carbon technologies, would not set the sector on the right pathway to 2050. However, there is a clear challenge for the policy maker in determining to what extent it may be appropriate to mitigate the possibility of adverse outcomes through further interventions or market changes.

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1 Introduction

1.1 Background

On the 26th November 2008, the Climate Change Act became law in the United Kingdom (UK) and established a long term, legally binding framework to help transition the UK towards a low carbon economy by 2050. Amongst the provisions of the Act was a target reduction in CO_2 emissions of 26 percent by 2020 and 80 percent by 2050[2]. The Committee on Climate Change's (CCC's) inaugural report, "Building a low-carbon economy - the UK's contribution to tackling climate change" set out some of the challenges in meeting these targets, and also outlined how the move to a low-carbon economy could be achieved through existing technologies, supported by appropriate policies.

The Committee set out its recommendations for carbon budgets for the UK for three 5-year periods out to 2022. These included intended targets, and interim targets which should apply prior to an international deal on climate change. In May 2009, Parliament agreed the first three interim budgets and these are now set in law. The interim budget for the final period, 2018-2022, would require reductions in carbon dioxide emissions of 34 percent from 1990 levels (or 21 percent compared to 2005 levels).

The targeted reduction in carbon emissions is consistent with one of the four objectives around which energy policy in UK has been formed over recent years. The other three objectives have been:

- maintaining the reliability of energy supplies;
- promoting competitive energy markets in the UK; *and*
- ensuring that every home is adequately and affordably heated.

Success in reducing the UK's greenhouse gas emissions will be strongly dependent on large-scale decarbonisation of the power sector. This will necessitate a move away from unabated fossil fuels towards cleaner forms of generation including greater use of renewables, nuclear and thermal plant fitted with carbon capture and storage (CCS). This changing profile of generation will result in an electricity system whose operation and dispatch characteristics will increasingly differ compared to today's system. This includes increased reliance on intermittent[3] generation; a higher proportion of generation from plant with low short run marginal costs; and changing demands on flexible plant able to provide back-up generation and reserve.

The pursuit of decarbonising the power sector and achieving success in meeting the long term CO_2 emissions targets may have implications for achieving equal success in the other three objectives of energy policy.

[2] In a letter to the Secretary of State for Energy and Climate Change in September 2009, the Committee advised that in order to accommodate continuing growth from the aviation sector, this target reduction may need to increase to 90% across the rest of the economy.

[3] We use the term "intermittent" in this report to describe renewable generation technologies whose output varies with the resource in question, including wind, wave, tidal and solar. (Others use the term "variable" in an equivalent way.) Of these, tidal is fully predictable, whilst the others are dependent on uncertain weather patterns. Whilst all plant can be considered intermittent to some extent (due to forced outages), intermittent renewables are not dispatchable on demand in the same way as thermal plant (although they can be "controlled down" to reduce output below the level it would otherwise be at).

1.2 Objectives of the study

The CCC has commissioned Redpoint to undertake modelling and analysis to assess the investment pathways to 2030 that lead towards decarbonisation of the power sector. In particular, it is seeking to explore the development and operation of an electricity sector that is characterised by:

- low emissions intensity;
- secure and reliable sources; *and*
- prices that provide sufficient returns for investors whilst ensuring any cost increases to consumers are minimised.

Whilst the analysis naturally places at its centre the achievement of decarbonisation targets for the electricity sector, with the policies necessary to achieve them, the CCC is also seeking to explore how achieving decarbonisation may be balanced against the impact on alternative priorities and values, in particular security of supply, market efficiency, resource costs and the wholesale costs to the consumer. Similarly, it is keen to understand the sensitivity of outcomes to paths and assumptions, and the impact on decarbonisation where policies vary.

The CCC is also interested in understanding the extent to which market arrangements may need to evolve to deliver such an electricity sector by 2030, including the way in which plant is dispatched, new capacity is incentivised, and transmission congestion is managed.

To address the questions posed we have deployed an analytical modelling framework to assess quantitatively the evolution of the power sector through to 2030. Our modelling of the market captures endogenously the relationship between Government policies, investor decisions and expected future market conditions. The modelling provides an objective framework against which emissions, electricity prices and security of supply can be assessed over the next twenty years. The modelling is conducted within the framework of the current market arrangements, and we have additionally assessed qualitatively how these may potentially evolve, drawing in part on the quantitative analysis and in part on current experience in the UK and internationally.

As the CCC is keen to understand how meeting the Government's emissions reduction targets will impact the other pillars of energy policy, analysis is centred around a scenario in which investors behave "rationally" against a given set of assumptions. By rational behaviour we mean that investors make timely investment decisions based on their prevailing cost of capital, with reasonable (but not perfect) foresight on the future demand / supply balance, and with reasonable knowledge of future carbon (EUA) prices. The scenario includes several assumptions that the CCC considers significant to achieve the objective of being on the pathway towards full decarbonisation of the power sector by 2030. We apply the name 'Environmentally Favourable Conditions' (EFC) to this scenario, to reflect the primary focus of reducing CO_2 emissions. The significant features of the EFC scenario that lead to long term decarbonisation are:

- Energy efficiency measures reversing the historic trend for positive growth, with both annual and peak electricity demand falling from today's levels through to 2020 and then remaining constant thereafter as energy efficiency gains keep track with rising demand for energy services stemming from such factors as population and gross domestic product (GDP) growth.
- Meeting a target in which 32 percent of electricity demand in 2020 comes from renewable sources.
- EUA prices rising to the levels required to meet the EU's 2020 30 percent greenhouse gas emissions[4] reduction target and, thereafter, rising to levels required consistent with a global

[4] The CCC's EUA price projections are based on assumption that there will be an international agreement on climate change and therefore the targeted reduction in GHG emissions increases from the current legally binding target of 20% to 30% by 2020.

agreement to further reduce emissions by 2050, with prices thus driven by a global marginal abatement cost curve. These policy objectives manifest in EUA prices of approximately 40 €/tonne in 2020, rising steeply to 120 €/tonne by 2030, and continuing upwards to over 155 €/tonne in 2037.

If there is to be a single theme characterising energy markets through time, it is that they are inherently unpredictable. Part of this stems from different perspectives amongst market participants on what the future holds, and different priorities for policy makers, regulators, participants and individuals with regard to the environment, prices, security of supply, and market structure. Some of the uncertainties are explored through additional sensitivities around the EFC scenario.

The sensitivities reflect different outcomes in terms of UK policy (e.g. achievement of renewables targets) and different assumptions on exogenous drivers (e.g. global oil prices). These sensitivities are presented in the following Table 1 and Table 2.

Table 1 Sensitivity summary – UK policy

Name	Description	Reference
Severn Barrage	Government decision to build the 8.6 GW Cardiff-Weston Severn Barrage	1- SB
Peak prices dampened	An assumption that market rules prevent peak prices rising above 500 £/MWh even where the marginal value of electricity is greater.	2 – PP
Transport and heat electrification, all periods	Increasing electrification of the heat and transport sectors causing electricity demand to start rising again from 2023 across all periods.	3 – EP
Transport and heat electrification, offpeak hours only	As above, but with demand growth concentrated in the offpeak periods only.	4 - EO
Low renewable generation	Achieving only 25 percent of electricity supply from renewable sources by 2020.	5 - LR
High renewable generation	Achieving a higher renewable electricity target of 36 percent of electricity supplied by 2020.	6 – HR
Low renewables and electrification	Low renewable generation combined with transport and heat electrification, off peak-hours only.	7 – LR-EO

Table 2 Sensitivity summary – Exogenous factors

Name	Description	Reference
Low interconnector flexibility	A reduction of export capability at times of high wind output, given a higher assumed correlation between wind output in GB, Ireland and Continental Europe.	8 - LI
High fossil fuel prices	A scenario with High commodity prices: crude at 150 $/bbl flat post-2015	9 – HF
Low fossil fuel prices	A scenario with Low commodity prices: crude at 50 $/bbl flat post-2015	10 – LF
Low EUA fuel prices	EUA prices rise slowly post-2020	11 – LE
Low fossil fuel price and low EUA prices	A sensitivity combining Low fuel and Low EUA prices	12 – LF-LE
EUA prices at CCS break-even	EUA prices at a level just sufficient to stimulate investment in CCS	13 – EC
High demand	Higher GDP growth leading to higher electricity demand.	14 – HD

As evidenced by the world today, there are times when investors may behave in what economists might term an "irrational" manner, due perhaps to increased aversion to risk or to a shifting perspective on how risky the world is. Given the radical changes expected to take place within the electricity sector in the next two decades, such behaviour is likely to continue, if not become more pronounced, with uncertainty about the future exacerbated by the fundamental changes which investors know are coming. Hence, a number of alternative investor behaviours were tested against the EFC scenario to compare the market outcomes in a "rational" investment world with outcomes in which investors have behaved differently. The alternative behaviours are summarised in Table 3.

Table 3 Sensitivity summary – Investor behaviour

Name	Description	Reference
EUA myopia	Investors lacking faith in future carbon policy with investors basing their decisions on prevailing carbon prices rather than on an expectation of higher carbon prices in the future.	15 – EM
Higher hurdle rates	A higher degree of risk aversion for investors, manifested in a requirement for a higher level of return on investments.	16 – HH
Demand myopia	No consensus amongst investors over future demand changes, with investments based on demand in the year in which the decision takes place.	DM
Outturn price expectation	Investment decisions weighted more heavily towards current rather than potential future conditions.	PM

The final set of cases that were analysed combined sensitivities on the input assumptions with different assumptions of investor behaviour. These are summarised in Table 4.

Table 4 Sensitivity summary – Combining sensitivities

Combined sensitivities	Reference
EUA myopia + Transport and heat electrification, all periods	17 – EM-EP
EUA myopia + High renewable generation	18 – EM-HR
EUA myopia + Low interconnector flexibility	19 – EM-LI
EUA myopia + Higher hurdle rates	20 – EM-HH
EUA myopia + Demand myopia + Transport and heat electrification, all periods	21 – EM-DM-EP
EUA myopia + Outturn price expectation	22 – EM-PM
EUA myopia + Higher hurdle rates + Low interconnector flexibility	23 – EM-HH-LI
EUA myopia + Higher hurdle rates + Peak prices dampened	24 – EM-HH-PP
Higher hurdle rates + Low EUA prices	25 – HH-LE

1.3 Report structure

Prior to presenting the detailed results of the quantitative analysis, Chapters 2 to 5 of the report provide a higher level narrative with regard to the development of the electricity sector, in which we combine insights from the quantitative analysis with more qualitative observations:

- Chapter 2 draws on the results of the modelling to highlight some of the challenges for decarbonisation, investment and security of supply. This chapter focuses predominately on the market in 2030, rather than the pathway through to 2030.
- Chapter 3 analyses some of the key issues which may arise over the next 20 years and what they might mean for the strategies of utility players, independent generators, the system operator (SO), the regulator and policy makers.
- Chapter 4 is a detailed discussion of the operation of the system under the EFC scenario and across the range of sensitivities. In particular, we consider the level and pattern of wholesale electricity prices, the corresponding signals for investment, the resulting capacity mix, and the consequences for security of supply and system flexibility.
- Chapter 5 steps back from the modelling and considers in a qualitative manner potential developments in market arrangements for dispatch, incentivising the provision of capacity, and the management of network connections and constraints.

We present our detailed modelling results in two Appendices - A and B:

- Appendix A contains a full discussion of the EFC scenario, including key assumptions and modelling outputs.
- Appendix B provides, in an abbreviated form, the results of each sensitivity.

1.4 Caveat

This study was commissioned by CCC in January 2009, and the analysis is based upon information available at that time. The CCC has provided certain input assumptions for the modelling including demand growth rates and EUA prices.

Since this analysis was completed in Spring 2009 there have been important announcements on future energy policy by the EU and UK Government that would have had an impact on the outcomes of some of the sensitivities presented in this study. These include:

- Industrial Emissions Directive (IED): The analysis took place prior to the final negotiations of the IED, which aims to place further restrictions on the SO_x, NO_X and particulate emissions from coal and certain gas-fired plant. Our assumptions for the IED are presented in A.2.5.
- Clean coal: The analysis predates the announcement by the Secretary of State for Energy and Climate Change, Ed Miliband, on 23rd April 2009 (and publication of the subsequent consultation document[5]), that all new coal plant must be at least partially fitted with CCS and that there will funding available to support three further demonstration projects in addition to the current competition for a CCS demonstration plant.
- Incentives for Renewable Electricity: in mid-July 2009 the Government launched a consultation on the incentives for Renewable Electricity. This included proposals for modifications to the existing Renewables Obligation (RO) and the introduction of Feed-In Tariffs (FITs) for smaller renewable plant.

In addition to the Government policy announcements, the following should also be noted:

- In March 2009 Ofgem launched Project Discovery, which is an investigation into whether or not future security of supply can be delivered by the existing market arrangements over the coming decade.
- In June 2009 National Grid launched a consultation "Operating the Electricity Transmission Networks in 2020." This consultation document describes and examines the likely issues relating to operating the electricity transmission networks in 2020.
- Finally, in August 2009, a new report commissioned by the Prime Minister was published titled "Energy Security: a national challenge in a changing world." The paper stresses energy supply should be a national priority as the UK makes the transition to a low carbon economy.

1.5 Conventions and terminology

The modelling results in this report are for Great Britain (GB) – England, Wales and Scotland. The electricity market for Northern Ireland is a part of a combined market across the island of Ireland, the Single Electricity Market, which was not included within the scope of this study.

The pricing basis for the analysis is real 2008 money.

[5] DECC, A framework for the development of clean coal: consultation document

Certain terminology is used throughout the report:

Wholesale costs to the consumer

This is a measure of the component of the domestic consumer bill that comprises the wholesale electricity price, subsidy costs, balancing costs and BSUoS charges). It does not include transmission and distribution charges, or the costs of energy efficiency measures.

Capacity Margins[6]

The key indicator we use to assess security of supply between the EFC scenario and the variant sensitivities is the de-rated capacity margin. This is a measure of expected peak availability compared to peak demand. This takes into account the probability that plant of different types will be unavailable at certain times. For conventional plant this captures the risk of forced outages, and for intermittent renewables their expected contribution to security of supply based on probabilistic analysis of output levels.

The energy margin is a measure of the total available generation compared to annual demand. The energy margin captures annual restrictions on plant operation resulting from EU environmental legislation such as the Large Combustion Plant Directive (LCPD) and Industrial Emissions Directive (IED).

[6] See section A.3.3 for a detailed definition.

2 Challenges to 2030

2.1 Introduction

For the UK to be set on a path to meeting its 2050 target of an 80 percent reduction in greenhouse gas emissions, the electricity sector will need to look radically different by 2030. Over seventy percent of GB's generation will need to come from low carbon technologies, up from around a quarter today. It is becoming increasingly clear that a range of technologies will be needed to achieve this and in particular renewables, nuclear and carbon capture and storage (CCS) will play significant contributions.

Each of these, however, faces its own set of challenges. Most renewables are still uneconomic at today's electricity prices without subsidies, and the needed scaling up of supply chains and the transmission network will be difficult. Nuclear, whilst considered to have the lowest long run marginal cost in today's market[7], is very exposed to changes in commodity and carbon prices, and the long lead times and huge scale of the initial investment poses risks for investors. CCS is as yet unproven on a commercial scale, so large scale deployment may be shown to be technically unrealistic and costs in the longer run are highly uncertain.

On the demand side, there is equally a huge amount of uncertainty. The scale to which efficiency measures will deliver is unproven, and the timing and extent of electrification of the heat and transport sectors could lead to big changes in the level and shape of electricity demand. The technology to support a much more dynamic interaction between demand and supply – starting with the roll-out of smart meters – could play an increasingly important role, alongside increasing levels of small-scale distributed generation.

From the policy maker's perspective, the challenge is to ensure that investors are making decisions based on price signals and expectations that are reflective of the Government's longer term decarbonisation goals and the social costs of different options, to find effective ways to provide subsidies for currently uneconomic or pre-commercial technologies, and to ensure that the resulting allocation of risks between investors and consumers (or tax payers) is appropriate.

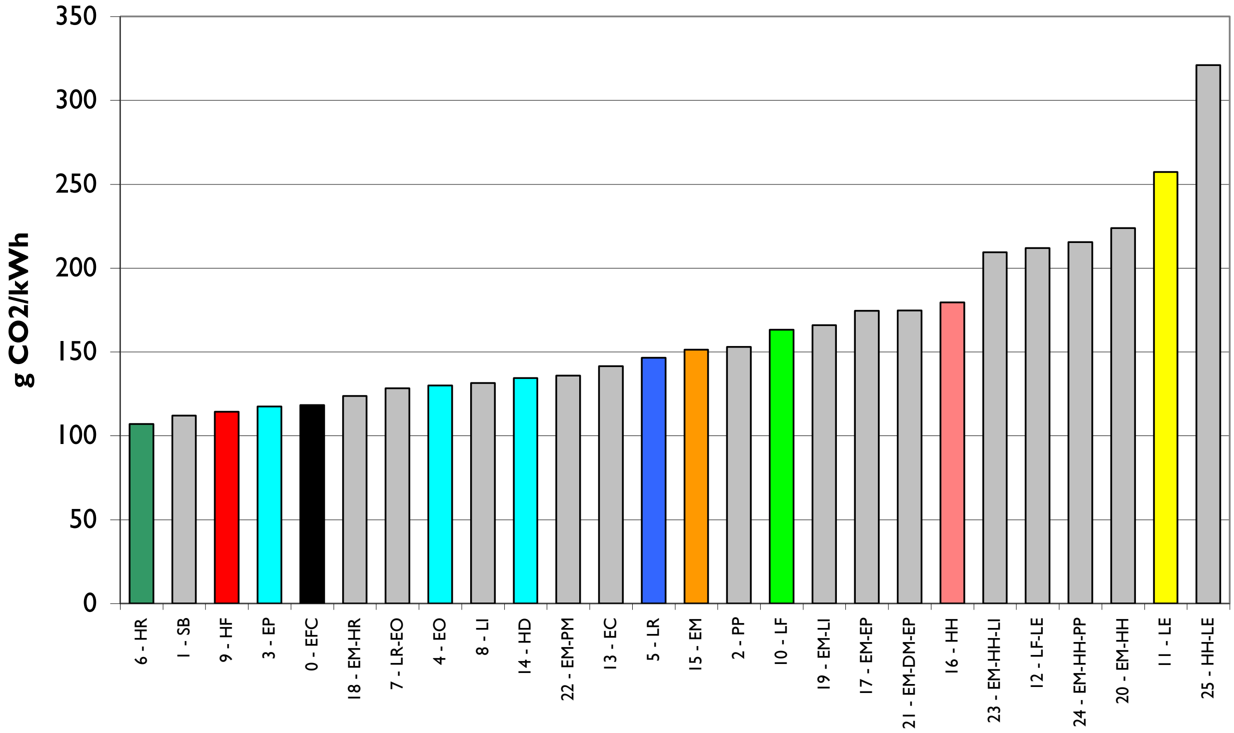
In this section, we use the results of our quantitative analysis to illustrate the key risks from the perspective of investment in generation capacity with regard to decarbonisation, security of supply, and costs to consumers.

2.2 Decarbonisation

Figure 1 shows the range of carbon emission intensities in 2030 across our sensitivities.

[7] Based on fossil fuel price projections in the EFC scenario.

Figure 1 Carbon emission intensity in 2030 by sensitivity



(Specific sensitivities discussed in the text are referenced by number and colour. A detailed description of the sensitivities can be found in Appendix B).

In the EFC scenario (*0 – black*), carbon emissions fall from around 450 g CO_2/kWh in the short term to around 120 g CO_2/kWh by 2030: this is marginally above the levels set out in the CCC's 2008 report[8] but is on a trajectory consistent with achieving full decarbonisation by 2050. However, across the range of our sensitivities, this varied significantly, and in the worst case (25 - the combination of High hurdle rate and Low EUA pricing) was still at 320 g CO_2/kWh in 2030.

We varied a range of assumptions in our sensitivities. Most significant (as a single factor) was the carbon price. Where EUA prices remain low (rising to little more than 40 €/t CO_2 by 2030 instead of 120 €/t CO_2), carbon intensity reduces to 260 g CO_2/kWh (*11 – yellow*), renewables deployment post-2020 is greatly reduced, there is no further CCS build beyond the first competition plant, and there is still significant generation from unabated coal in 2030.

Even if EUA prices do rise, if investors do not build this expectation into their decisions, there are significant adverse consequences for decarbonisation and costs. Although emissions intensity reduces to 150 g CO_2/kWh by 2030 (*15 – orange*), our model shows new build of unabated coal after 2020 – which rapidly loses load factor and profitability when the EUA price subsequently climbs, stranding the assets.

The level of fossil fuel prices has a significant impact on the build profile and emissions. Higher fuel prices improve the economics of new build, with additional nuclear and renewables coming onstream, and earlier deployment of CCS. Emissions intensity in 2030 is lower than EFC, at 110 g CO_2/kWh by 2030 (*9 – red*). Likewise, where fossil fuel prices are low, investment in low carbon technologies is slowed, and emissions

[8] CCC, Building a low-carbon economy, Figure 5.

intensity is 170 g CO_2/kWh (*10 – green*), with much less of the generation capacity in place that would be needed to achieve the required CO_2 emissions reductions after 2030. (As the commodity prices in this sensitivity favour gas over coal generation, aggregate emissions through to 2025 are actually lower than in EFC, although post-2025 the lack of investment in low carbon technologies leads to a less favourable outturn in 2030,)

Where demand is higher than the EFC scenario and assuming that investors are able to anticipate these changes, there is a corresponding response in the level of new build in generation and the impact on emission intensity is relatively limited. Overall emissions reflect the higher demand level (*3,4,14 – blue*).

Were investors' perception of risks to increase significantly, investment could be lower and slower, and would lead to less investment in higher capital cost technologies, such as nuclear and renewables. We tested this with higher hurdle rates, which resulted in a lower share of low carbon (high capital cost) generation by 2030 in our model, replaced by more (low capital cost) gas-fired generation. Emissions intensity reduces to 180 g CO_2/kWh (*16 – pink*) in this case.

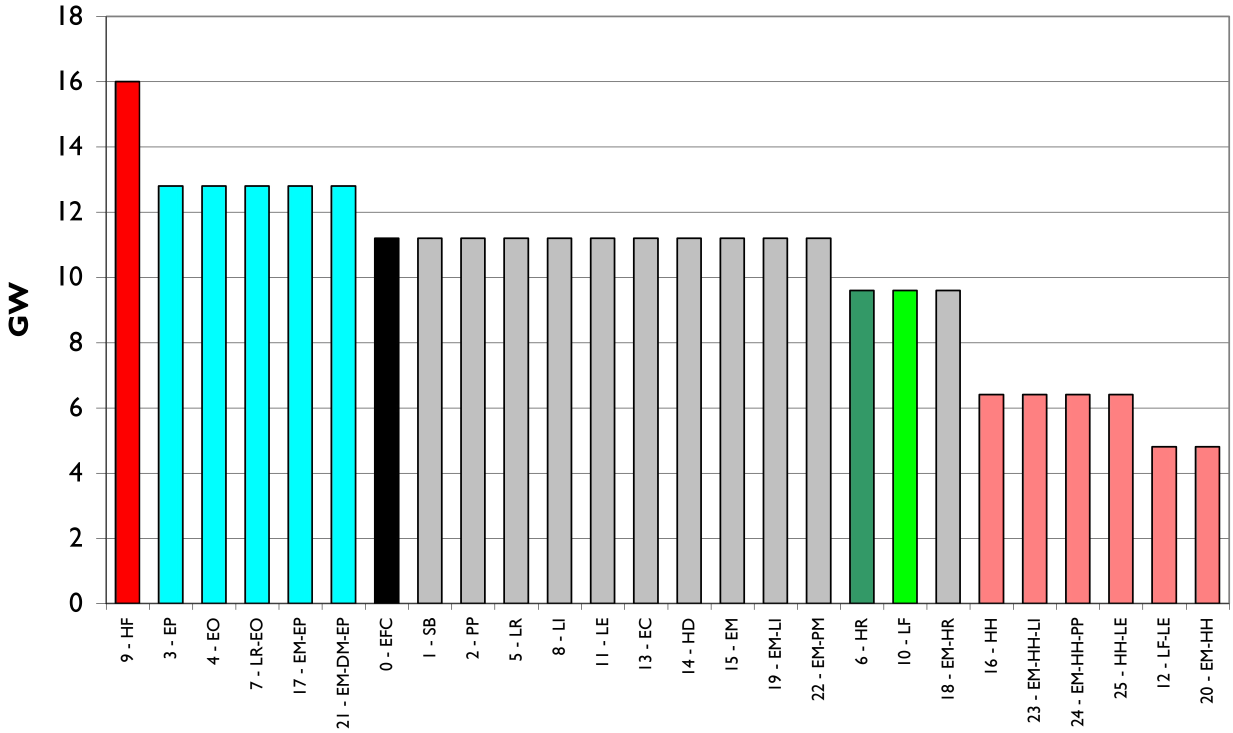
Renewables build reflects the success or otherwise of achieving renewables targets in the electricity sector. By successfully achieving a 32 percent target in EFC scenario, around 29 GW of new renewables are installed by 2030, compared to 21 GW if only 25 percent is achieved. With the lower renewables build, CCGT build increases relative to the EFC scenario, and as a result carbon intensity in 2030 is higher, at 150 g CO_2/kWh (*5 – dark blue*). Where a higher renewables target is achieved (36 percent in our sensitivity, with 38 GW of build), there is likewise a sustained benefit in emissions, reducing to 110 g CO_2/kWh by 2030 (*6 – dark green*).

The environment for nuclear becomes more challenging under higher levels of renewables penetration, as there is a greater proportion of low marginal cost plant on the system pushing prices down. Renewables themselves get some sort of protection from this effect through the subsidies they receive. More flexible thermal plant may be able to capitalise on higher peak prices that may result during period of low renewables output.

As shown in Figure 2, the model indicates that there would be some impact on build levels, with a reduction of new nuclear build from 11.2 GW under the EFC scenario (*0 – black*) to 9.6 GW under the High renewable generation sensitivity (*6 – dark green*). The effect of greater levels of renewables is similar to that of lower fossil fuel prices (*10 – light green*) on nuclear build. The sensitivities with the greatest consequences for nuclear build are those where hurdle rates are increased to reflect a higher level of perceived risk, with build reduced to between 4.8 and 6.4 GW (*12,16,20,23,24,25 – pink*)[9]. The electrification sensitivities increase new nuclear build above those seen in the EFC scenario, to 12.8 GW (*3,4,7,17,21 – light blue*), due to an expansion in the size of the 'baseload' market. The most significant upwards impact on nuclear is higher fossil fuel prices, which lead to 16 GW of build by 2030 (*9 – red*). In many cases, nuclear build would be higher based on purely economic grounds, but in all cases apart from the High fossil fuel sensitivity, where we assume there are additional efforts to develop the supply chain, nuclear build is constrained by a maximum annual deployment of 1.6 GW.

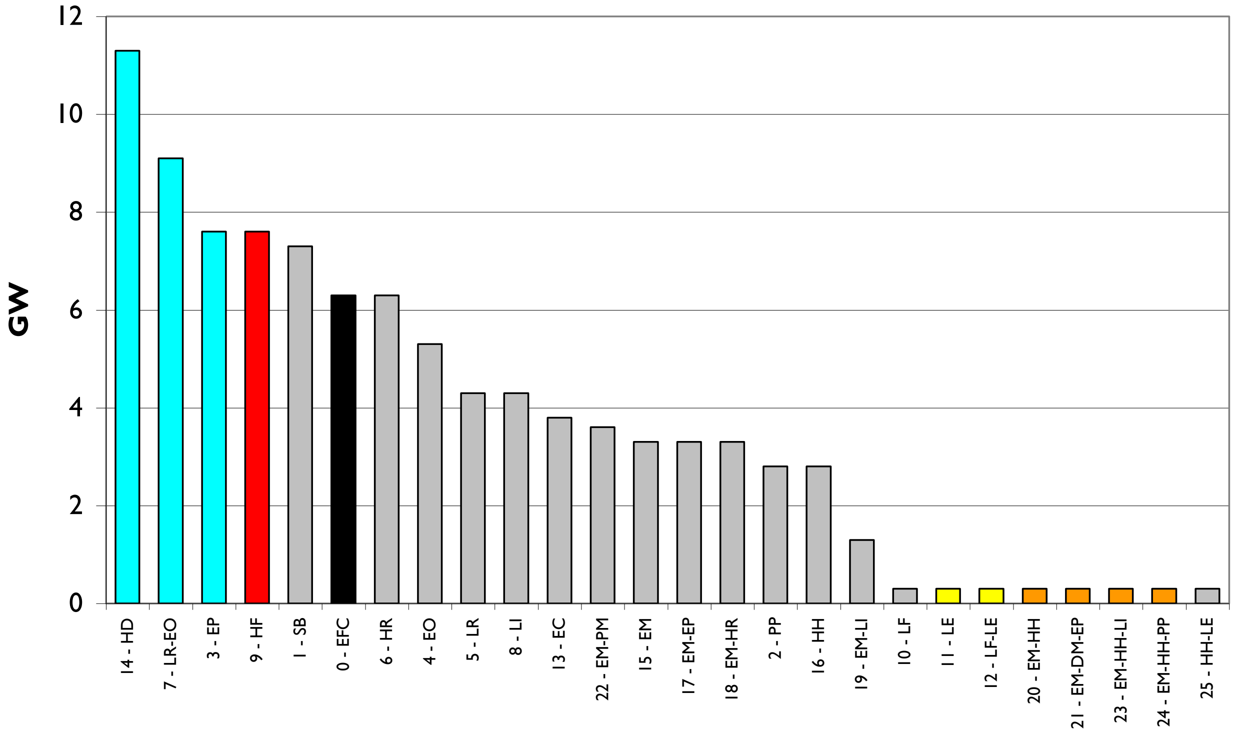
[9] Higher nuclear capital costs would have a similar effect.

Figure 2 Nuclear build by 2030



As shown in Figure 3, the level of CCS deployment by 2030 spans a wide range around the 6.3 GW of build in the EFC scenario (*0 – black*). (We assume in all cases that CCS is technically proven, that capital costs reduce by 20 percent and thermal efficiency improves by 15 percent over the scenario.) In a number of sensitivities where EUA prices are either low (*11,12 – yellow*) or where the increase in EUA price over time is not foreseen by investors (*20,21,23,24 – orange*), there is no build beyond the assumed 300 MW demonstration plant, and in other cases with either higher hurdle rates or again where the rise in EUA price is not anticipated, build is reduced to less than 3.5 GW. Build is higher in several of the high demand sensitivities (*3,7,14 – light blue*), and when fossil fuel prices are higher (*9 – red*).

Figure 3 CCS build by 2030



In a number of cases, there is new build of unabated coal plant (of between 1 and 6 GW). This happens either due to investors not foreseeing higher carbon prices, or in particular situations where there is opportunity for particularly high infra-marginal rents[10] (such as in the High fossil fuel sensitivity), or where demand is higher in the shorter term and where the rate of nuclear is constrained. Load factors decline rapidly but there is still some unabated output in 2030. Where EUA prices are low, or where we have assumed higher hurdle rates, then, whilst this does not lead to new unabated coal build, some existing coal plant are still running in 2030.

Since this analysis was completed for the CCC, the Government announced policy that will further drive the development of CCS technology in GB. The consultation[11] on the financial incentive arrangements for further CCS was closed in September 2009 and this could provide financial support for up to four commercial-scale CCS demonstrations in Britain. In the modelling we have assumed that only one demonstration CCS plant is commissioned. Clearly additional CCS plant would further reduce emissions relative to the EFC scenario.

2.3 Security of supply

Our principle measure of security of supply is the de-rated capacity margin. Under the EFC scenario, this rises from 10 percent in 2009 to 21 percent with new build through to 2012, before seeing a significant

[10] Infra-marginal rents can be earned where the short run marginal costs of the plant are less than those of the marginal price setting plant. New investments can earn infra-marginal rents where the new plant is either more efficient than the price setting plant or uses a cheaper fuel and/or is less carbon intensive than the price setting plant.

[11] DECC, A framework for the development of clean coal: consultation document

decline to 6 percent with the impact of LCPD closures[12] to 2016 and nuclear closures to 2019. Further coal plant opt for a limited hours running regime post-2016 and retire over the subsequent five to seven years rather than fitting the required NO_X emissions reduction equipment, as would be required under the IED.

After 2020 the de-rated capacity margin stabilises, fluctuating between 7 percent and 12 percent to 2030. This is a level that is lower than that seen historically, and there is a small risk of energy unserved (i.e. involuntary demand reduction) in some years. However, our modelling suggests that levels of involuntary demand reduction would be no greater than those typically experienced today as a result of transmission and distribution outages. We assume in the model that demand side response increases over time, but it is very possible that developments here beyond those we have assumed would reduce the risk of involuntary interruption.

The modelling suggests that at these levels of de-rated capacity margin, peak prices would rise significantly during periods of low wind output, whilst being suppressed at other times. Under these conditions investment in CCGTs could still be attractive. With their relatively greater flexibility and lower capital costs, CCGTs can afford to operate at lower load factors than higher capital cost plant that need to run close to baseload in order to secure a reasonable return on investment. They can run to capture the higher peak prices and turn off when prices fall low or even negative. Higher peak prices may also encourage older plant to stay on the system rather than retire, provided they can cover their fixed costs. Under these conditions a reasonably healthy capacity margin can be maintained under the EDF scenario.

The situation may also be different if peak prices are dampened. There may be reasons why very high prices could be suppressed. For example, at times of system stress (when peak prices would be expected to occur), the System Operator (SO) will be likely to be deploying a range of balancing tools (including system reserve, free voltage control, and automatic demand disconnection). If these are not correctly priced, then actions by the SO may dampen market prices.

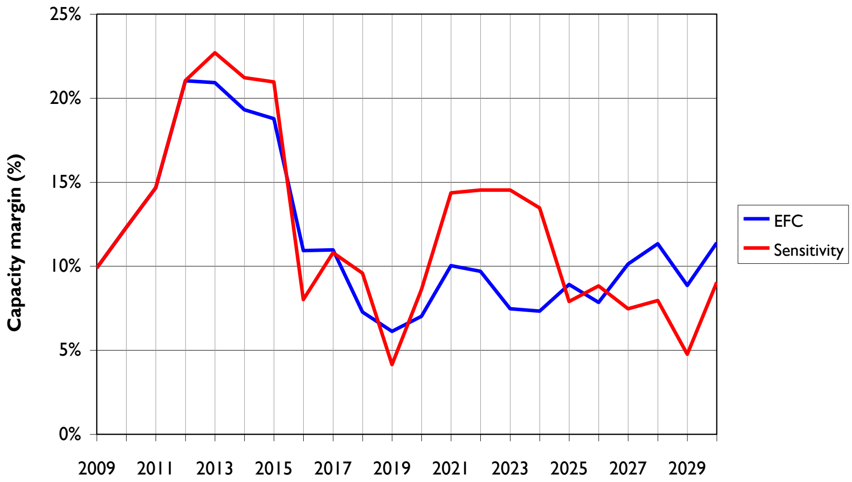
Recent evidence suggests that the current market rules do indeed dampen peak price signals. For example, consider the events of 27th May 2008. In the morning, a sudden loss of 1.6 GW of generation in two minutes led to the triggering of some automatic low frequency relays. In the run-up to the evening peak, National Grid issued instructions to Distribution Network Operators to reduce demand. Despite the system being very short and load shedding occurring, the price in the Balancing Mechanism reached only 313 £/MWh[13].

We have tested this under our Peak prices dampened sensitivity. In this case, the de-rated capacity margin is more erratic and falls below the EFC scenario in a number of years, as shown in Figure 4.

[12] Approximately 11.9 GW of coal and oil capacity has opted-out of the LCPD requiring it to close by the end of 2015.

[13] For more details, see "Report of the investigation into the automatic demand disconnection following multiple generation losses and the demand control response that occurred on the 27th May 2008", National Grid

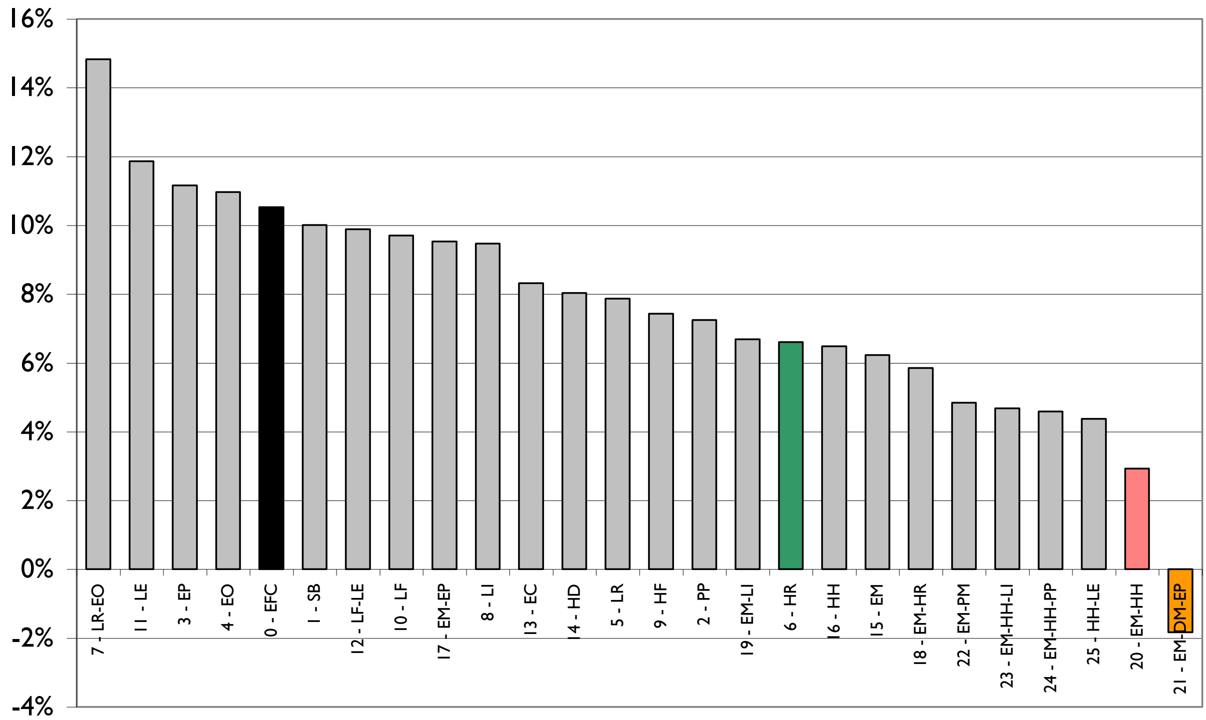
Figure 4 De-rated capacity margin: EFC and Peak prices dampened



Constrained peak prices depress margins for low load factor plant, leading to earlier retirements. This in turn leads to periods of low capacity margin but this pushes up prices more generally, spurring investment.

In a number of our sensitivities, as we show in Figure 5, de-rated capacity margins decline further on average, particularly where new investment is lower than the EFC scenario (*0 – black*). As discussed above, this can be due to investor expectations on carbon prices that are lower than outturn, or where perceived risks are higher. Where both of these occur together, the modelled de-rated capacity margin averages only 5 percent from 2020 to 2030 (*20 – pink*), and the average energy unserved is ten times that in the EFC case, albeit still only 13 GWh per annum.

Figure 5 Average de-rated capacity margin, 2028-2030, by sensitivity



At higher levels of renewable generation, such as in the High renewable generation sensitivity, there is further downward pressure on baseload prices, thus further reducing the profitability for other plant. Whilst overall new investment is not significantly affected in our sensitivity due to the high EUA price, this does cause a higher level of retirement in the last few years to 2030, and hence a decline in capacity margin (*6 – dark green*), which dips to 4 percent in 2029.

The sensitivity with the most variable de-rated capacity margin is where neither EUA price increases nor changes in demand (associated initially with efficiency measures, and later with electrification) are correctly anticipated by investors. Here the de-rated capacity margin is correspondingly higher through to 2020 as investors 'overbuild' relative to lower demand, but then falls sharply to 2029 as the subsequent increases in demand is not matched by sufficient new build (*21 – orange*). In practice it is likely that the consequences of such a scenario would be significantly less extreme, as the development of electrification (an exogenous input in the model) would be likely to be constrained (either economically or politically) if investment in generation had not met the required levels to support the growth in demand.

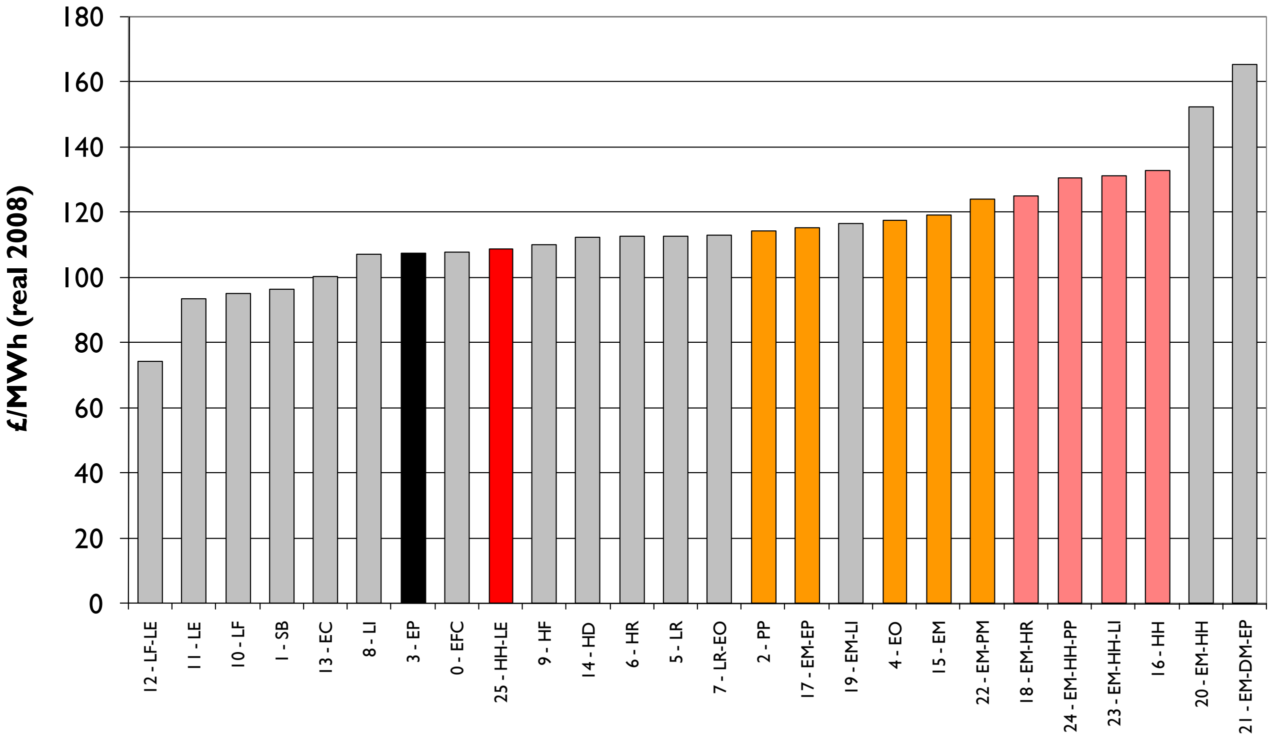
Maintaining security of supply with more intermittent renewable generation on the system, will place greater demand for the provision of flexibility from conventional thermal assets. The analysis shows that in most cases the system will be capable of delivering this flexibility (assuming that new plant are at least as flexible as today's fleet), although in some extreme outcomes there could be energy unserved as a result of lack of flexibility. In reality we would expect greater response from the demand side to provide some of this flexibility.

2.4 Prices

Under the EFC scenario, rising fossil fuel and carbon prices push up the marginal cost of generation. The lower average levels of capacity margin after 2015 also lead to higher levels of price uplift[14] as prices rise during periods of tight supply. Consumers also bear the increasing cost of the Renewables Obligation, which peaks in 2027 at around £6bn/year.

Figure 6 shows the wholesale costs to the consumer, averaged from 2025 to 2030, for our sensitivities. Fossil fuel prices are likely to be the biggest driver of prices prior to this period, but after 2025, whilst there is still some impact (*9 – red*), other factors begin to dominate as the proportion of times that thermal plant set the price decreases. Lack of investor anticipation of future price and demand increases (*15,17,18,19,22 – orange*), and consequent under-investment, tends to lead to higher costs for consumers as tighter margins push prices up, increasing profits for generators. Higher perceived risks for investors (*16,20,23,24 – pink*) hurts consumers both through lower investment levels, but also through higher financing costs driving up costs of capital. This created some of the worst outcomes for consumers in our sensitivities.

Figure 6 Wholesale costs to the consumer, 2025-2030, by sensitivity



In most sensitivities thermal plant, particularly gas, remains the price-setting technology throughout the duration of the scenario. Even towards the end of the 2020s, prices are largely set by gas plant, despite the market share of gas plant being less than 12 percent and the sharply rising EUA price. This creates opportunities for significant infra-marginal rent earnings for low marginal cost plant, and drives investment in these technologies. However, moving beyond the time-horizon of the scenario, the increasing amounts

[14] Uplift refers to the increases in price above short run marginal costs of the marginal plant which can occur when margins are tight. In these situations generators are able to capture a 'scarcity rent' which they may need to earn to recover the fixed costs of operating their plant.

of low marginal cost plant could lead to lower outturn prices and presents a risk of sharply falling infra-marginal for these plant.

Prices also become more volatile. By 2030, there are periods of 'spill', where supply from inflexible generation (primarily wind and nuclear) exceeds demand, driving prices to zero and below. At the other end of the spectrum, prices peak to higher levels when supply is tight (such as at times of low wind). Although the potential earnings for plant remain sufficiently attractive to stimulate investment in a world of increasingly volatile prices, the increasing volatility may increase the perception of risk for flexible generation plant. Load factors will reduce as low marginal cost plant gain market share, and there will be fewer period in which flexible thermal plant earn infra-marginal rents. There will however be an increase in the number of periods of very high price periods, and plant increasingly depend on these periods to recover fixed and investment costs.

The level of spill is substantially a function of levels of wind and nuclear on the system compared to demand levels. Interconnectors also play an important role in avoiding spill by enabling power to exported during periods which would otherwise spill. Spill is significantly higher (up to 5 percent of the year in 2030) in the high renewables sensitivities and under higher fossil fuel prices (when nuclear build is higher). Despite the higher levels of spill, there is only a very marginal impact on investment in nuclear and CCS plant, as the high carbon price outweighs the downward price pressure from the spill periods. Sensitivities with higher demand, or lower nuclear or wind build, typically have very low spill levels.

2.5 Summary of risks

Table 5 summarises the risks identified in the discussion above, and provides a qualitative assessment of the potential impact on:

- emissions intensity in 2030;
- build of low carbon technologies (nuclear[15], and CCS);
- build of unabated coal (higher build shown as negative impact);
- de-rated capacity margin (averaged from 2028-2030); *and*
- domestic prices (averaged from 2025-2030).

The table draws on the results of the modelling and therefore the outcomes are, to a large extent, determined by the underlying scenario assumptions that have been made.

[15] The modelling makes exogenous assumptions about the level of renewables generation (32% in 2020 and 36% in 2030). The assumption is made that banding delivers the target level of renewables and therefore the sensitivities do not reveal a change in outcome based on the different risks.

Table 5 Risk summary

		Emissions intensity	Nuclear	CCS	Unabated coal build	Capacity margin	Domestic prices
Risk	Low carbon prices		*				
	Lack of anticipation of carbon price rise		***				
	Higher hurdle rates						
	High fossil fuel prices						
	Low fossil fuel prices						
	Dampened price signals						
	Higher demand		**				
	Unanticipated demand changes						

* Becomes less important if fossil fuel prices are high

** Higher expected demand positive under the electrification cases

*** Nuclear plant are in the money with the 'Low' EUA prices[16]; investors in nuclear are not dependent on visibility of the EUA price,

Our modelling indicates that, where investors make decisions in anticipation of rising carbon prices, and are correctly anticipating future scarcity, then a level of decarbonisation can be achieved by 2030 that is consistent with full decarbonisation by 2050 without undue impact on security of supply, albeit at a higher cost for consumers. However, there are a range of outcomes in which this may be jeopardised. The challenge for the policy maker is to determine to what extent it may be appropriate to mitigate against these by re-allocating risks from generators to consumers (or tax payers), and/or reducing the exposure (to commodity or carbon prices) for low carbon generation. The mechanism, or market arrangements, through which this is manifest, will impact on the earnings profile of different plant. Appropriate interventions may reduce the spread of possible outcomes from a de-carbonisation (or security of supply) perspective, but whilst increasing the potential burden on consumers. The possible implications for market arrangements are discussed further in Chapter 5.

[16] The 'Low' EUA prices reach approximately 50 €/t in 2030.

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3 Emerging issues in the electricity sector

3.1 Introduction

In the previous section we summarised some of the possible outcomes for the electricity sector by 2030, drawing on the key results from our quantitative analysis. In this section we describe in more detail the path to 2030, again using the EFC scenario and sensitivities to illustrate some of the key challenges and issues.

We break the timeframe down into four 5-year periods. For each period we describe what we think will be the key issues, summarise the main modelling outputs and describe the possible strategies of the main participants – utility players, independent generators, the system operator, regulator and Government. The further out into the future the greater the uncertainty surrounding the possible issues and outcomes.

3.2 The path to 2030

3.2.1 2010 to 2015

The likely generation mix over this period is largely known since the majority of the plants operating today will remain open and potential new additions are already in the development pipeline. This period is therefore likely to display similar operational characteristics to those currently experienced. The most interesting issues relate to the investment plans developed throughout this period which will have a significant influence on the nature of the system through to 2030 and beyond.

Therefore in terms of the impact on investment, there are a number of key issues:

- ***Prolonged financial crisis:*** the possibility that the recent turmoil in the financial markets will extend well into this period and exert a major influence on investor behaviour. Even assuming a reasonably rapid rate of recovery in financial markets there will be strong competition for equity and debt as the industry seeks financing for renewable and conventional generation projects, for network developments (e.g. offshore transmission), and for the implementation of smart meters.

- ***Medium term capacity shortage:*** the extent to which sufficient capacity is built to replace the 11.9 GW of plant opted-out under the Large Combustion Plants Directive (LCPD). Currently there is approximately 9 GW of thermal capacity at advanced stages of development (see Table 15 for details); coupled with the recent decline in demand the acute need to develop capacity to coincide with the closure of the LCPD opt-out plant has somewhat receded. There does however remain a need for further projects to be initiated in the period 2010 – 2015.

- ***Progress towards renewables targets:*** the rate of renewables build and the progress that is made towards meeting the 2020 renewable energy targets. The Renewable Energy Strategy published in Summer 2009 set out the path for meeting the legally-binding target of 15 percent of energy from renewable sources by 2020. However there remain significant challenges in delivering this volume of renewable energy.

- ***Clean coal demonstration:*** the success in proving CCS technologies through demonstration plant. The first demonstration projects could be commissioned towards the end of this phase.

- ***Nuclear new build:*** the commitment and development of plans for new nuclear build. Whilst we would not expect to see any new nuclear plant developed until towards the end of the next decade at the earliest, we would anticipate that developers will progress projects into the construction phase during the period 2010 – 2015.

Modelling outputs (2010 – 2015)

The most significant conclusions of the modelling work undertaken for this period are that:

- investors continue to push ahead with a variety of generation projects; *and*

- sufficient plant, predominantly combined cycle gas turbines (CCGTs), are built to replace plant closed as a result of the LCPD.

The de-rated capacity margin gradually increases throughout this period for two primary reasons. First, new capacity is brought online in anticipation of LCPD induced closures by the end of 2015, and second, there is a steady fall in demand (on top of recent reductions caused by the recession) as energy efficiency measures are more widely adopted. Emissions of CO_2 from the generation sector remain broadly constant and are driven by the relative costs of coal and gas generation. Electricity prices broadly follow fossil fuel prices. Table 6 presents a number of metrics to characterise the market over this period: similar metrics are produced for each subsequent period to enable comparison through the scenario. The table shows the outcome in the EFC scenario, and the range in outcomes across the 25 sensitivities.

Table 6 Modelling outputs, 2010 to 2015

Metric	EFC	Range[17]
CCGT build	9.2 GW	7.2 to 10.4 GW
Coal fitted with CCS build	0.3 GW	0.3 GW
Unabated coal build	None	None
Nuclear build	0 GW	0 GW
Renewables build	9.8 GW	9.4 to 14.3 GW
Average de-rated capacity margin	17.8%	16.1 to 20.2 %
Annual average CO_2 emissions from the generation sector	156 mt	124 to 157 mt
Annual average wholesale costs to the consumer	70 £/MWh	49 to 110 £/MWh

Utility players (2010 – 2015)

The UK energy market is likely to remain a key target market for the major European utilities. This is because:

- the UK is a large European market;
- it is at the leading edge of liberalisation;
- corporate ownership structures make it relatively easy to 'do deals' to unwind or increase market positions;
- there is a mature regulatory system with reliable checks and balances;
- attractive market opportunities exist given the capacity requirements created by expected closure of LCPD opted-out plant; *and*
- the UK has a significant and largely untapped renewable energy resource.

Typical forward projections of commodity prices suggest that the economic choice between coal and gas plant is finely balanced. However, CCGTs are generally accepted as the technology of choice by investors because of the relative ease with which the plant can be built, lower capital at risk, the fact that CCGTs present the cheapest economic option at lower load factors, and the robustness of CCGTs to higher carbon prices since for the majority of the period they remain the price-setting technology.

However, strong industry concerns remain that over-reliance on gas leaves energy companies open to risks of price spikes and supply interruptions, and it is therefore accepted practice for large companies to

[17] The range is for the average derated capacity margin across the period, for all sensitivities.

maintain a diverse generation portfolio. This is particularly true in light of events between Russia and Ukraine in January 2009, which intensified worries about the predicted increase in reliance on gas imports to meet demand. With minimal gas storage capacity and decreasing reserves of North Sea gas, investors will be looking for investment in additional gas storage facilities, gas pipelines and liquefied natural gas (LNG) re-gasification terminals to maintain strong confidence in CCGT investment.

Nuclear generation has emerged as the preferred alternative large scale generation technology since it is robust to high carbon costs and most of the largest portfolio players are pushing ahead with a programme of nuclear development. However, there are limits to the extent and speed of a nuclear build programme and some utilities may also want to pursue investments in coal fired power stations to maintain a sufficiently diverse generation portfolio. Any such decision must now take into account developing Government policy on CCS, and in particular the announcement on 23rd April 2009 by the Secretary of State for Energy and Climate Change. This laid out proposals that new coal plant must be at least partially fitted with CCS technology, and that a full-scale retrofit of CCS will be required within five years of the technology being independently judged as technically and commercially proven.

Large utility generators own a portfolio of existing power station sites. These sites offer the potential to obtain connection agreements to the grid with much shorter lead times than those typically available for new power station sites. This creates a strong incentive for utility generators to re-use existing sites. For carbon-emitting plant, however, it will now also be necessary to consider the suitability of the location for future application of CCS technology.

It is likely that incumbent players will see particular opportunities in developing renewable energy projects in the UK. They are well placed to manage the financial risks associated with the Renewables Obligation (RO) and experience of the mechanism suggests that good returns are available in the UK provided build constraints and connection queues can be overcome.

Independent developers (2010 – 2015)

The UK market is also attractive to independent developers for similar reasons to those described above for incumbent players. However, independent developers do not have the benefit of a portfolio of assets with which to manage risk and they will look for each separate investment to provide a secure and predictable return. Moreover, the legacy of the recent turmoil in the financial markets is likely to affect the ability of independent developers to obtain finance for any projects which have a material risk and this may last for some time to come.

Renewables projects are likely to remain a key area of focus for independent developers. However, the risks associated with the RO support mechanism are easier to manage within a diverse generation portfolio than on a stand-alone basis. It is therefore likely that most independent developers will be developing large scale renewables project on the basis that they will sell on to an incumbent player at some point in the future. The Government has indicated that it will introduce a Feed-in Tariff for small scale (not greater than 5 MW) projects, which would reduce the risk for independent developers without the need for these to be sold on.

Independent players will also continue to review conventional generation options. The advantages of CCGTs described above are particularly relevant for independent developers and it is less likely that they would consider nuclear or coal/CCS investments. However, the current situation with connection to the grid presents a major obstacle for independent developers looking to develop a new generation site since connection timescales of around ten years are typically being offered. It is only likely that projects will be pursued if grid connection is available in the short term.

The current situation in the financial markets and with grid connection issues suggests that few, if any, large independent generation projects are likely to proceed in the near future. It is likely that the financial markets will recover during the 2010-15 period and reforms are planned for the transmission access regime[18]. Therefore, interest on the part of independent developers may increase during this period. However, this is only likely to translate into new power station projects if the unfolding energy policy and market agenda leads to a perception of reducing future risk. It is, however, possible that new power stations may be built by other European utilities looking to enter the UK market for strategic reasons.

System operator (2010 – 2015)

Under its current licence obligations, the System Operator (SO), National Grid Transmission (NGT), is tasked with contracting for and utilising options to manage supply and demand on the electricity system in real-time. This involves real-time energy balancing, alleviating transmission constraints, frequency control and the provision of reserve to deal with unexpected changes in generation or consumption. The SO achieves this through a combination of pre-contracted balancing services with generators and large consumers, and a real-time balancing mechanism where generators and consumers can offer and bid to increase or decrease their output or usage.

Two potential challenges the SO faces are a concern around insufficient investment in flexible capacity in the longer term, and a more challenging short term balancing task as intermittent renewable capacity increases. Furthermore, much of the capacity that currently provides balancing services, such as oil-fired plant, will close before 2016 under the terms of the LCPD.

The first of these clearly relates to the uncertain investment environment we have described above. The SO is already able to enter into longer term contracts with market participants for the provision of certain balancing services, and it is incentivised to do this (currently on an annual basis) in the most efficient manner. Were the concern around investment considered to be sufficiently serious, one way to address this may be to change the licence conditions for the SO to oblige it to procure longer term capacity (for say ten years ahead), probably in conjunction with a specific security of supply remit. The downside of this is that it might displace private investment that may have taken place anyway.

With regard to short term balancing, it is likely that the future of power system operation will be characterised by three phases:

- Phase 1: Broadly as now
- Phase 2: Enhanced requirement for gas-fired plant to provide system balancing services such as reserve and to operate at low load factors
- Phase 3: Development of active demand side providing load shifting and balancing services

The timescales for these phases are extremely uncertain and depend on:

- development of grid infrastructure including interconnections to other power systems;
- the rate of growth in renewable generation and the operational characteristics of the wind fleet; *and*
- innovation in the way electricity is used, including the extent to which demand increases as a result of the electrification of the heat and transport sectors.

Most commentators believe that we will remain in Phase 1 throughout the period 2010-2015 and therefore the behaviour of the SO will be largely unchanged. However, it is possible that changes to the transmission

[18] The Government is currently consulting on options to change the grid access arrangements which could accelerate connection of new renewables to the grid in advance of network reinforcements.

access arrangements may mean that the SO will increasingly have to deal with system constraints which arise through the intermittent operation of renewable plant. This would reflect the acceleration of renewables connections ahead of full firm connection availability as part of the "Connect and Manage" phase of the enduring arrangements proposed in the Transmission Access Review[19]. It may therefore be the case that the SO will be seeking increased flexibility from generators (and large demand sources) in certain geographical locations. Further phases of the evolution of the arrangements are designed to reduce congestion.

During the period 2010-2015 it is likely that the SO will be increasingly focused on the future system balancing challenges and assessing the performance characteristics of the increasing wind fleet. As a consequence of this analysis, it is likely that the SO may propose new incentive mechanisms to encourage greater system flexibility in the years after 2015.

Regulator (2010 – 2015)

The market framework and investment climate suggest that there are ongoing drivers for consolidation in the GB market. It is therefore likely that the regulator will face further competition cases relating to proposed mergers and acquisitions and also claims of adverse effects due to market dominance.

It may be that these issues increasingly bring into conflict the competitive nature of the energy market and the need to attract investment. It is therefore likely that the regulator will spend significant amounts of effort during this period reconciling the economic and sustainability aspects of its duties.

The occurrence of transmission constraints tends, from time to time, to create sub-markets in which certain players are in a temporary position of market dominance. Increasing renewables penetration during this period will exacerbate this problem. Ofgem has already indicated that this is an area in which new, more targeted, measures may be necessary[20].

Government (2010 – 2015)

Significant effort has been devoted to developing the policy framework for the generation market over the last few years, building on the market-based approach that has been a policy goal since privatisation. Whilst the onshore transmission system remains a regulated "natural monopoly", investment decisions in generation are left to market participants. Market signals (such as the EU ETS, the RO and proposed Feed-in Tariffs (FITs) for sub-5MW generation) are used to guide these investments in line with Government objectives.

There is an increasing challenge to this approach in the context of a radical decarbonisation of the electricity sector. In addition to the RO and sub-5 MW FITs, specific support for CCS is being channelled through funding of up to four demonstration projects including the Government's existing competition plant. There are also calls for more explicit intervention to facilitate nuclear deployment, for example by introducing a carbon price floor. Some argue that at some stage it becomes more efficient for Government to directly set the required capacity mix and levels (for example through central tendering) rather than aiming to achieve the same effect indirectly through a complex set of market interventions. It is likely that this debate will be played out in the 2010-2015 period.

A key area for proactive policy development is likely to be on the demand side of the market where it is accepted that radical new initiatives are required to improve levels of energy efficiency and, ultimately, promote a responsive and active customer base. The Government has signalled its intent to develop the

[19] http://www.berr.gov.uk/energy/sources/renewables/policy/transmission-access/page40567.html

[20] Ofgem has recently consulted on a range of measures to mitigate the risk of exploitation of locational market power, including the introduction of a Market Power Licence Condition (MPLC), which follows on from concerns around the costs of resolving constraints between England and Scotland and within Scotland.

demand side via the goal of introducing smart meters in all homes by 2020. It is possible that this focus may have implications for wholesale market policy if it is decided that the features of the wholesale market in some way constrain the development of competition in the demand side. This might include, for example, making changes to settlement procedures or the Balancing Mechanism to facilitate demand side participation.

Furthermore, sending clear and early signals about the carbon price, and enforcing those signals through perhaps a floor price, will build investor confidence in believing the required carbon price will materialise. This confidence building will ensure that investment decisions taken beyond 2015 are based on this price; an expectation that is necessary if decarbonisation to be achieved.

Robustness to 'events' (2010 – 2015)

There are many plausible events that could adversely affect the energy market and trigger a policy intervention. However, it is likely that the Government will be focusing on the following major risks:

- international climate change agreements fail to deliver a strong carbon price signal to the market;
- renewable build levels fail to increase to the rates needed to meet the 2020 targets;
- CCS technology demonstration does not move forward throughout this period;
- increasing dependency on gas-fired generation reduces the diversity of the energy mix;
- nuclear investment plans go on hold; *and*
- insufficient new capacity is built to replace LCPD closure plant.

Maintaining security of supply will always remain a primary policy goal and Government will be closely monitoring the rates at which new plant are being built. In the event that a problem is encountered, the Government retains a number of policy levers to incentivise capacity to remain on the system or for the development of further new capacity.

In addition, a number of domestic policy initiatives are available to reinforce the carbon price signal through, for example, imposition of a floor price for carbon. Similar fiscal incentives may also be considered to reinforce investment signals for CCS or nuclear development.

However, the most challenging problems would relate to technical obstacles which are preventing the development of renewable, nuclear or CCS plant and the response of the Government would need to depend on the particular nature of the issues and their severity.

3.2.2 2016 to 2020

The second half of the next decade may see a second phase of fossil plant closures arising from the Industrial Emissions Directive (IED) and, therefore, there will be an ongoing need to build sufficient replacement capacity to preserve security of supply. However, by this stage, progress with a number of key policy measures will have become apparent:

- Deployment of renewables will have progressed such that the ability to hit 2020 targets will be known and it is possible that further targets beyond 2020 will have been established. Moreover, the operational characteristics of an intermittent wind fleet will begin to be understood along with the impact on system operation and the value of other sources of generation.

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- The potential capacity of the replacement nuclear fleet will become clear as the first new stations are commissioned and a series of follow-on stations will be under construction and in the development pipeline.

- The robustness of CCS technology, and the associated economics, will now be better understood, enabling a much clearer picture of potential deployment and informing decisions around further additional policies, potentially including the application of emissions performance standards to new and existing fossil plant.

- The growth in annual energy demand may have been halted and reversed following a major push to improve energy efficiency, although electricity demand may at some point start to increase again if there is increasing electrification of the heat[21] and transport sectors.

It is also possible that during this period, new technologies may be in the process of development that could significantly alter the energy system during the 2020s, for example:

- major advances in renewables such as solar and wave/tidal;

- new energy storage technologies; *and*

- a rapid expansion of electric vehicles.

It is unlikely that the future will seem any more certain than in the previous 5 years and, in addition, there will be new operational challenges arising from the changes in the electricity system.

Modelling outputs (2016 – 2020)

The modelling runs suggest that the 2020 renewable targets could be hit within the current policy framework if appropriate use of re-banding is employed, energy efficiency measures are implemented to reduce demand and the development of renewable plant is no longer restricted by planning delays, poor financing conditions, lack of grid connections or supply chain constraints. In other words conditions prevail that are synonymous with delivering successful decarbonisation of the power sector. Also, sufficient non-renewable capacity continues to be built to maintain security of supply, although the system will be operating at slightly lower capacity margins and, therefore, at a slightly higher risk that some firm demand may not be met at times. CCGTs remain the primary source of new non-renewable capacity and the volume built will adjust depending on market need (which can be between zero and 14 GW): in this period the level of CCGT build in a sensitivity is determined by the relative economics between new CCGT and existing coal and CCGT plant – i.e. how much infra-marginal rent a new plant could earn.

By 2020, CO_2 emissions are forecast to begin to reduce, primarily driven by a reduction in coal generation and increasing reliance on generation from renewables. However, where investors do not believe in the Government's projections for the EUA price and in the absence of any regulations to the contrary, investors would build unabated coal plant. (Clearly, the April 2009 announcements, subsequent to our analysis, remove the possibility of this outcome.) Electricity prices remain closely related to fossil fuel and carbon prices. A summary of the key modelling outputs is shown in Table 7.

[21] Greater electrification of the heating sector may result from an expansion of heat pumps to support the renewables heat targets, or by more electricity being directly used for heating should offpeak prices fall in response to the growing expansion of renewables.

Table 7 Modelling outputs, 2016 to 2020

Metric	EFC	Range
CCGT build	2.4 GW (Cumulative: 11.64 GW)	0 to 14.4 GW (Cumulative: 9.2 to 21.6 GW)
Coal fitted with CCS build	0 GW (Cumulative: 0.3 GW)	0 to 2.5 GW (Cumulative: 0.3 to 2.8 GW)
Unabated coal build	0 GW (Cumulative: 0 GW)	0 to 2.5 GW (Cumulative: 0.3 to 2.8 GW)
Nuclear build	1.6 GW (Cumulative: 1.6 GW)	0 to 1.6 GW (Cumulative: 0 to 1.6 GW)
Renewables build	13.4 GW (Cumulative: 23.2 GW)	2.5 to 15 GW (Cumulative: 12 to 28.4 GW)
Average de-rated capacity margin	8.5 %	5.7 to 16.2 %
Annual average CO_2 emissions from the generation sector	126 mt	88 to 136 mt
Annual average wholesale costs to the consumer	88 £/MWh	60 to 133 £/MWh

Utility players (2016 – 2020)

A key challenge for utility players during this period will relate to wholesale market risk management, since it is likely that significant new costs or profit opportunities will emerge. In particular, the large portfolio players will need to decide how to manage short term volume risk on the part of their growing intermittent renewable fleet. Traditionally, portfolio players look to manage their own exposure and take advantage of balancing market opportunities through holding reserve on thermal plant. However, some conventional peaking capacity will have closed in 2015 (particularly the large oil plant) and more will likely close in the period through to 2020. Therefore, investments will need to be made to ensure replacement thermal plant is sufficiently flexible to meet the system balancing needs.

However, self-balancing by the utilities will tend to restrict liquidity in the short term markets and therefore increase costs of risk management should the incumbent's assets fail to provide sufficient flexibility. It is therefore possible that utilities will consider switching to strategies in which more significant volumes are traded through the short term markets in an attempt to minimise balancing costs. Alternatively, a view may develop that there is an overall economic efficiency gain in a single entity (presumably the SO) assuming a deeper role in balancing the system. In its extreme this could be introduced through a return to central dispatch for all plant, but a more targeted approach might limit this specifically to intermittent renewables.

The key investment challenge for utility players during this period relates to the extent that new CCGTs continue to be planned and built to meet the capacity need compared to investment in nuclear and new coal with CCS technology. This decision will depend on the nature of the market opportunity (volumes and prices, particularly likely future carbon prices) and the status of CCS technology and the financial support available. Where carbon prices are expected to be high and CCS technology has been successfully demonstrated, it is likely that utility players will look to maximise nuclear new build and meet the residual opportunity with coal and CCS. However, if the available volume for new plant is likely to have a low load factor and higher carbon prices are not foreseen, it is more likely that incumbents will continue to build CCGTs.

Independent developers (2016 – 2020)

It is unlikely that the investment climate for independent developers will change significantly throughout this period. There are likely to remain significant opportunities in the field of renewable project development, however, the price risks inherent in the RO will mean that independent developers are still likely to look to sell large developed projects to large portfolio players. The hurdles in developing large conventional plant may rise since it is unlikely that wholesale market risk will fall over this period to a level at which independent developers are comfortable making investments, or can obtain financing on sufficiently viable terms. Changes in risk management behaviour by incumbents which increase short term market liquidity will be helpful but are unlikely to be sufficient to underpin major long term investments.

System operator (2016 – 2020)

Assuming that growth in renewable generation is in line with the 2020 targets, the SO will be experiencing a more challenging operational environment. This challenge is likely to be exacerbated by any tightening in the de-rated capacity margin, as suggested by the modelling runs, or by an increasingly constrained transmission network.

It is therefore likely that the SO will be adopting new operational practices, based on experience gained with higher wind capacity, and seeking new sources of balancing services, particularly from the demand side and interconnectors. The increase in demand for balancing services may have led to the design of a new and longer term balancing services market in which a forward price for 'flexibility' is created. Such a price signal would help investors in new power plant and in other sources of balancing services value their investments.

As noted above, there may be a move for the SO to be more directly involved in balancing (rather than acting to manage the residual position), at least for intermittent renewables. This would require a significant scaling up of its balancing capabilities during this period.

Regulator (2016 – 2020)

Depending on the scale and planning of new transmission investment through to this point, and the success or otherwise of longer term transmission access arrangements, concerns with regard to transmission constraints, and associated market power issues, may have increased further. The regulator may be looking to adapt or extend measures introduced in the previous period, with a focus on ensuring that transmission constraints do not give rise to excessively high consumer costs.

In addition, attention will focus on the short term markets, and the extent that portfolio players act to maintain liquidity in the short term markets.

Government

If it has not already happened, the period 2016-2020 could see a renewed focus on wholesale market design as attention is placed on achieving power system targets for 2030 and beyond. This may involve delivering increasing levels of renewable generation beyond the 2020 targets and, possibly, seeking to decarbonise fully the system by 2030.

In the event that carbon price signals are high and retain the confidence of investors and that the demand side of the market is increasingly active, it may be that relatively little action is required. However, if investors remain highly uncertain about the nature of the future market opportunity then the Government may seek to introduce policies which promote certain forms of investment.

Robustness to 'events' (2016 – 2020)

It is possible for the geo-political environment to have moved significantly by 2016-2020, placing either an increased or reduced incentive for energy self-sufficiency and either increasing or reducing the costs of significant carbon abatement. However, it is likely that politicians will wish to maintain a diversity of energy options to provide confidence in ongoing security of supply as well as the ability to decarbonise the system. In particular, this latter imperative may demand investments in low carbon technologies that become ultimately redundant as other options prove more successful. This in turn is likely to require ongoing subsidisation to promote diversity beyond that provided by an energy price and carbon price signal.

3.2.3 2021 to 2025

It is extremely uncertain how much new capacity is required during the period after 2020 and what type of new capacity will be required. It will depend critically on:

- the levels of system demand;
- ongoing growth rates for renewable generation; *and*
- the extent of the new nuclear build programme.

It is likely that there will be some ongoing need for new thermal capacity, however, the choice between gas and coal (with CCS) will depend critically on:

- forward views of carbon prices;
- the technical options for carbon abatement;
- the role that new generation needs to play in providing balancing services; *and*
- any minimum operational standards (e.g. flexibility requirements) or environmental standards imposed on new generation capacity.

It is also possible by this stage that new minimum emissions performance standards, or an explicit requirement to retrofit CCS, will be applied to existing thermal capacity in, say, 2025, leading to a similar capacity 'cliff-edge' to that seen in 2015. This would further increase the need for new capacity during this period.

By the period 2020-2025, it is likely that new technologies will be under development that will have a significant impact on the operation of the electricity system after 2030, and new generation investments made at this time will need to take account of these ongoing and potentially significant changes.

Modelling outputs (2021 – 2025)

The modelling runs indicate a wide range of new capacity investment over this period (between 3 GW and 21 GW). Between 1.6 and 4.8 GW of new nuclear plant are built with the highest volume in the cases in which the electrification of the transport sector is increasing overall system demand but also leading to a flatter profile of demand. New build thermal capacity varies between 0 and 6.4 GW with CCGTs remaining the technology of choice under most scenarios. Where investors have confidence in high future carbon prices, significant investment occurs in coal with CCS. However, where this is not the case, the modelling suggests that some unabated coal plant might still be built (assuming no CCS requirement is imposed). A full summary of modelling outputs is shown in Table 8.

Table 8 Modelling outputs, 2021 to 2025

Metric	EFC	Range
CCGT build	5.2 GW (Cumulative: 16.8 GW)	0 to 8 GW (Cumulative: 12.4 to 27.6 GW)
Coal fitted with CCS build	0 GW (Cumulative: 0.3 GW)	0 to 2.8 GW (Cumulative: 0.3 to 5.6 GW)
Unabated coal build	0 GW (Cumulative: 0 GW)	0 to 6.0 GW (IGCC) (Cumulative: 0 to 6 GW) 0 to 3.0 GW (ASC) (Cumulative: 0 to 3.0 GW)
Nuclear build	3.2 GW (Cumulative: 6.4 GW)	1.6 to 4.8 GW (Cumulative: 1.6 to 8 GW)
Renewables build	4.0 GW (Cumulative: 27.2 GW)	0.1 to 16 GW[22] (Cumulative: 18.8 to 37.9 GW)
Average de-rated capacity margin	8.7 %	6.1 to 13.6 %
Annual average CO_2 emissions from the generation sector	88 mt	67 to 113 mt
Annual average wholesale costs to the consumer	101 £/MWh	77 to 124 £/MWh

Utility players (2021 – 2025)

The levels of renewable generation will require large portfolio players to adopt sophisticated risk management strategies, involving a combination of asset dispatch (both generation and demand) along with trading in the short term markets. The short term markets may become increasingly liquid and, if so, the price signals generated may become the predominant price marker, exerting a significant influence over future expectations of power prices. Large portfolio players may experience increasing regulatory oversight of their trading activities within these markets.

From an investment perspective, it is likely that the companies will be restricting their future options to zero carbon generation since these assets would be expected to deliver a payback during the period after 2030. In this regard, they will be looking for a strong signal for investment in low carbon technology. Since the electricity system has largely decarbonised, and there is only a minimal amount of fossil-fuel generation that could set prices reflective of high carbon prices, the investment signal through the power price may not be sufficiently strong on its own.

Independent developers (2021 – 2025)

Beyond 2020, it is likely that the market will be characterised by both a high level of wholesale market risk and the need for capital intensive non-renewable generation plant. Both of these factors reduce the likelihood of a substantial involvement from the independent investment community in large scale renewables, other than in developing early stage and niche renewable generation projects or in partnership with large portfolio players. Independent developers may focus their efforts more on the sub-5 MW sector, where the FIT regime offers greater certainty in revenues.

[22] Includes Severn Barrage

In addition, by this stage the potential for CCS and renewables to contribute to longer term decarbonisation targets should be much clearer. This may present big opportunities for independent developers (alongside a mix of other players) to play a substantial role.

System operator (2021 – 2025)

After 2020, the balancing actions of the SO will be largely driven by the generation characteristics of the large fleet of intermittent renewable generators. It is likely that new approaches will have been adopted in light of experience gained in the operation of the system with an increasing proportion of renewables. In addition, it is likely that the SO will have a broader range of balancing services on which to draw including an increasingly active demand side. It may be that the SO is now regularly signing multi-year balancing services contracts to ensure adequate investment is being made in areas of greatest system need.

Regulator (2021 – 2025)

The role of the residual fossil fuel market will now be a significant concern to the regulator with a (probably) small number of fossil fuel generators setting a price which not only drives the investment in non-fossil plant but also needs to recover annual avoidable costs for the remaining fossil plant. Any concerns about potential abuse of market power are likely to be particularly severe if the demand side of the market has not developed to the extent that it is providing real competition to generation at the margin.

This situation will become progressively more acute as the system decarbonises and it is likely that the regulator will be seeking to identify solutions which maintain efficient pricing up to and beyond 2030.

Government

Policy time horizons will now be looking beyond 2030 and it is difficult to envisage where the key challenges may lie. However, it is likely that a focus will remain on driving the emergence of new technologies and incorporating them within the energy system to maintain a secure and efficient system going forward.

Robustness to 'events' (2021 – 2025)

By 2025 it is possible that we will be seeing an increasing number of weather 'events' in consequence of ongoing increases in global atmospheric temperature. It is possible that harsh weather conditions might be creating major challenges for the electricity system at this time leading to politicians placing particular focus on system resilience towards adverse weather conditions.

3.2.4 2026 to 2030

It is difficult to be certain of the key challenges facing the electricity system between 2026 and 2030. Perhaps new technological developments will suggest that it is possible to move towards a situation where a much greater proportion of power is generated by renewable sources by 2050. This may, for example, involve the bulk transfer of renewable power from remote locations producing offshore wind generation or concentrated solar power or possibly new technologies providing the potential for communities to meet all their power needs through locally produced renewable energy. Alternatively, it may be accepted that the potential for renewable energy is reaching saturation point and, in the absence of major technological advances, a decarbonised power system must be based significantly around nuclear and coal with CCS power stations.

These situations will bring very different challenges and investment needs. However, there is no evidence that the extent of the challenge looking out towards 2050 will be any less than we currently see as we attempt to predict the future of the market out to 2030.

Modelling outputs (2026 – 2030)

Between 2026 and 2030, today's policies, as well as investors' behaviour, will be dictating the nature of the system. In 2030 the EFC scenario represents a successful outcome in terms of policy goals: the electricity sector will be well on track to meet its 2050 carbon targets without significantly compromising security of supply. However, there are many permutations of outcomes consistent with delivering this policy goal. The precise form it will take will be a function of a complex range of factors, some within and some beyond the control of Government. For example, a market including very large scale Government-supported projects (such as a Cardiff-Weston Severn Barrage scheme) could have a carbon trajectory similar to one without. Security of supply could also be similar. However, the cost implications of the two alternatives are quite different.

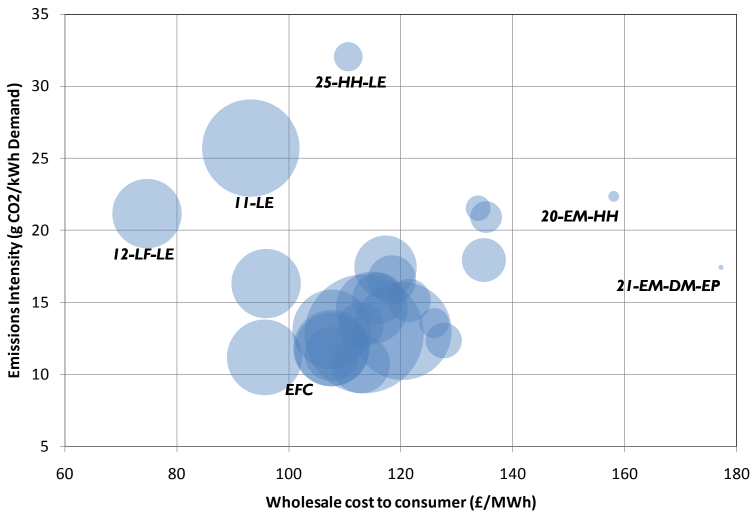
The system can also adapt to outcomes beyond the control of the Government, such as higher fossil fuel prices. Modelling of these sensitivities shows that the system is still well on its way to being de-carbonised, with total emissions in 2030 essentially the same as those with baseline commodity prices assumed in the EFC scenario. However, higher commodity prices result in one of the most "expensive systems" (based on the net present value of resource costs[23], excluding CO_2, between 2009 and 2030); the exact opposite is true for lower commodity prices. Towards the end of the 2020s however, the wholesale generation costs in the High fossil fuel case falls below the EFC scenario; there has been much more low carbon generation developed in the High fossil fuel case which is lowering outturn prices.

The range in outturn emissions across the sensitivities is wide, with a large number of cases leading to emissions higher than the EFC scenario. This is particularly the case where investors are not behaving "rationally", where the range of carbon emissions is 48 to 102 million tonnes, with all outcomes worse for emissions than under the EFC scenario. Security of supply is also adversely affected.

To illustrate the diversity of potential outcomes, Figure 7 plots three variables for 2030 across a range of sensitivities – emissions (on the y axis), consumer prices (on the x axis) and security of supply (indicated by the size of the bubbles).

[23] The change in the costs of generating electricity, including changes in investment costs, fuel costs, variable and fixed operating costs and system balancing costs. It excludes changes in the costs of carbon.

Figure 7 Potential outcomes



In summary, a de-carbonised world can coexist with adequate supply security if investors can be given the correct visibility and incentives (including the EFC scenario). Likewise, market outcomes with higher carbon emissions can also be associated with lower security of supply, particularly where this is a result of myopia or an increased perception of risk on the part of investors (22-HH-LE, 20-EM-HH, 21-EM-DM-EP). Low carbon outcomes are in many cases associated with lower wholesale prices. If however commodity and carbon prices themselves are low leading to lower wholesale prices then carbon emissions tend to be higher since the level of investment in low carbon technologies has been lower (12-LF-LE, 11-LE).

With regard to security of supply, the de-rated capacity margin will, in general, be somewhat lower than current typical levels. The key question is whether the system will be sufficiently flexible, both in terms of generation and demand side, to ensure that this does not give rise to an unacceptable security of supply risk. Key modelling outputs are summarised in Table 9.

Table 9 Modelling outputs, 2026 to 2030

Metric	EFC	Range
CCGT build	2.4 GW (Cumulative: 19.2 GW)	0 to 6.4 GW (Cumulative: 12.8 to 30.0 GW)
Coal fitted with CCS build	6.0 GW (Cumulative: 6.3 GW)	0 to 7.3 GW (Cumulative: 0.3 to 11.3 GW)
Unabated coal build	0 GW (Cumulative: 0 GW)	0 (IGCC) (Cumulative: 0 to 6.0 GW) 0 (ASC) (Cumulative: 0 to 3.0 GW)
Nuclear build	4.8 GW (Cumulative: 11.2 GW)	0 to 8.0 GW (Cumulative: 4.8 to 16.0 GW)
Renewables build	2.3 GW (Cumulative: 29.5 GW)	0 to 7.6 GW (Cumulative: 20.5 to 38.4 GW)
Average de-rated capacity margin	10%	1.6% to 13.3%
Annual average CO_2 emissions from the generation sector	46 mt	41 to 102 mt
Annual average wholesale costs to the consumer	108 £/MWh	75 to 177 £/MWh

Utility players and Independent developers (2026 – 2030)

It is likely that, by 2030, the investments that have proved most popular over the previous 20 years will no longer be appropriate (in the case of conventional thermal plant) or the resource available (in the case of low cost renewables); there may be a significant opportunity at this stage to re-power early onshore wind sites. Investors will therefore be looking to the technologies that appear to provide the most promising potential for the period up to 2050 and beyond.

The role of nuclear power is particularly interesting in this regard given the long development lead times and operational lifetimes. A nuclear project initiated in 2030 would need to provide a payback well into the second half of the century and investors would need to be confident in the market opportunity over that timeframe. It is therefore possible that technological innovations may slow down the development of new nuclear power stations during this period.

System operator (2026 – 2030)

The SO will be familiar with the challenges of operating a power system with large volumes of intermittent renewable energy by 2030 and new approaches and procedures will have become common practice by this stage. However, it is likely that new challenges will be emerging for the SO as a result of changes in the way electricity is produced. The SO may be spending much more time co-ordinating operations with neighbouring networks as a result of increased levels of interconnection. Alternatively, the task may be evolving into one of co-ordinating the balancing actions of local network operators. The interactive participation of the demand side may be evolving rapidly, with "smart grid" technologies widely deployed.

Regulator (2026 – 2030)

Despite the numerous changes that the electricity system will undergo, the fact that electricity is likely to remain an essential commodity coupled with the inherent imperfections of the electricity market, suggests that there will continue to remain a significant role for an economic regulator beyond merely regulating the monopoly network infrastructure. For example, it is possible that the system will have effectively broken down into a series of sub-markets which are transient in nature and give rise to temporary monopoly situations. The regulator will need to continue to tread the fine line between ensuring competitive prices for consumers whilst maintaining incentives for future investment. Extensive distribution and demand side response will also no doubt introduce new challenges in order to incorporate these most efficiently into trading arrangements.

Government (2026 – 2030)

By 2030 the focus of policy will be to establish a roadmap towards 2050 and, probably, a fully decarbonised power system. Depletion of global gas and oil supplies could well be driving policy towards achieving independence of these diminishing and, presumably, increasingly expensive, fuels.

It is likely that there will remain a debate as to which investments should be prescribed by Government and which should be left to the market to decide. Previous experience suggests that the focus of policy shifts between periods in which the shortcomings of the market are paramount and a larger role is created for Government and periods in which the shortcomings of Government are recognised and as many decisions as possible are left to the market. It is difficult to predict where we might be on this cycle by 2030.

4 Delivering a decarbonised system in 2030

4.1 Introduction

This chapter explores in detail what a low carbon electricity sector might look like in 2030. Specifically, we examine two questions:

1. Whether the market can deliver a sufficiently strong investment signal to ensure 'adequate' investment in new capacity by 2030?
2. Whether the capacity on the system in 2030 will be sufficiently flexible to meet demand and operate the system?

To answer the first of these questions we present in section 4.2 some of the results from the EFC scenario looking at wholesale electricity prices, investment signals and plant profitability. In particular we focus on the implications of changes in the shape of the price duration curve (the spot price for each half-hourly period order from highest to lowest) for the profitability of different types of plant. We then analyse security of supply in the EFC scenario using two measures, the de-rated capacity margin and the level of expected energy unserved, which is a probabilistic assessment of the amount of involuntary demand reduction that will occur in each year. The analysis presented in this section captures the complex interactions between investment decisions, prices and how the system is operated. The investment decision modelling assumes that prices are set based on competition between fuels to generate, and where the capacity margin becomes tight increase to reflect scarcity[24] up to an assumed value of lost load in cases where demand cannot be met.[25]. The discussion in this section is centred on the EFC scenario. Other sensitivities are used to highlight the messages as appropriate. The assumptions and results of the EFC scenario are discussed in more detail in Appendix A.

In section 4.3 of this chapter we address the question of whether the capacity that is on the system in 2030 is sufficiently ***flexible*** to manage effectively the variability in output from intermittent renewables and demand. In particular we look at within day variations in wind output ("wind swings") and the implications this has for the operation of thermal plant. We also consider the responsiveness of thermal plant to react to changes in demand and wind output forecasts. Since it is difficult to forecast network reinforcements out to 2030, we have not attempted to project transmission constraints for this analysis although it is likely that they will have an impact on the operation of the system.

4.2 Investment: prices, profitability and security of supply

The analysis demonstrates that the increasing proportion of low short run marginal cost plant (nuclear, renewables and, by 2030, CCS) on the system can push down wholesale prices in certain periods. The chance of low marginal cost supply exceeding system demand becomes material, and this can lead to very low or negative prices, as renewables compete to generate and continue to receive subsidy through ROCs, whilst at the same time other non-dispatchable plant is also generating. The occurrence of these low or negative price periods will very likely depress baseload prices. A key question therefore, is whether prices

[24] The relationship between prices, the short run costs of the marginal plant and the system margin has been calibrated using historical data.

[25] The Peak prices dampened sensitivity is an exception to this rule. In this sensitivity we assume that prices do not rise to reflect full scarcity value.

will increase sufficiently in other periods to remunerate existing capacity on the system, and to incentivise investment in either new generation capacity or demand side response.

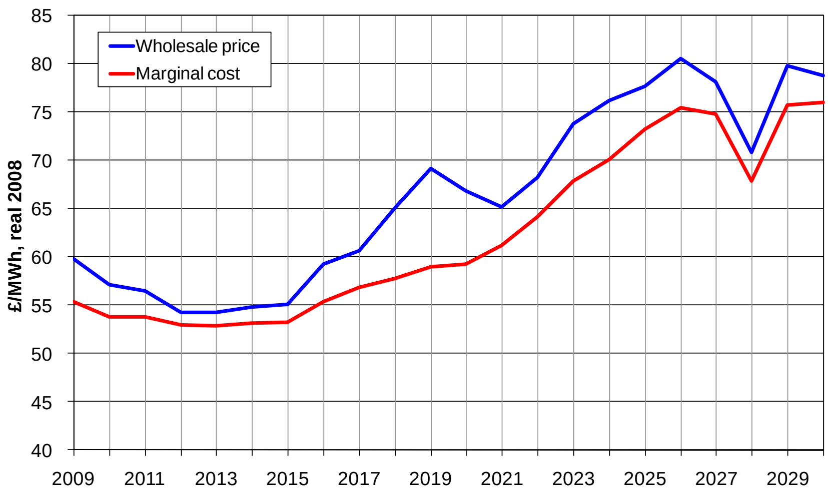
4.2.1 Prices

To understand the impact of high levels of intermittency on the market we analyse annual baseload prices and price duration curves or price 'shape'.

Wholesale prices

Figure 8 shows the annual baseload prices for the EFC scenario, alongside the short run costs of the marginal plant on the system. The difference between the two, referred to as 'uplift', reflects the extent to which prices increase above the marginal generation costs during times of scarcity. Uplift is important for maintaining investment signals if the system short run marginal generation cost is insufficient alone to cover fixed costs (including debt servicing costs) and earn a return on equity in the long run.

Figure 8 Annual baseload prices, EFC scenario



In the period to 2015, prices dip during a period of over-supply: the combination of the committed build and the near-term reduction in electricity demand increases the de-rated capacity margin. Uplift during this period is low since in most periods the price is set close to the short run costs of the marginal plant. Post-2015 prices trend upwards (other than a dip in 2028[26]) in line with increasing fuel and carbon prices. The range of uplift varies from year to year in line with de-rated capacity margins, so that lower de-rated capacity margins result in higher levels of uplift and vice versa. The upward trend in both baseload prices and marginal costs is in spite of the increasing proportion of nuclear and renewables on the system. This is because the strongly increasing carbon price offsets the impact of more low short run marginal plant on the system depressing price. However, towards the end of the 2020s prices start to flatten off, and if we were to extend the series beyond 2030 electricity prices would begin to fall (despite commodity prices remaining high) as the proportion of low marginal cost generation further increases. This suggests that with thermal plant setting the price for less and less of the time, the role that the carbon price has in providing

[26] The commissioning of over 5 GW of low marginal cost generation (nuclear, Coal with CCs and renewables) causes the dip in prices in 2028.

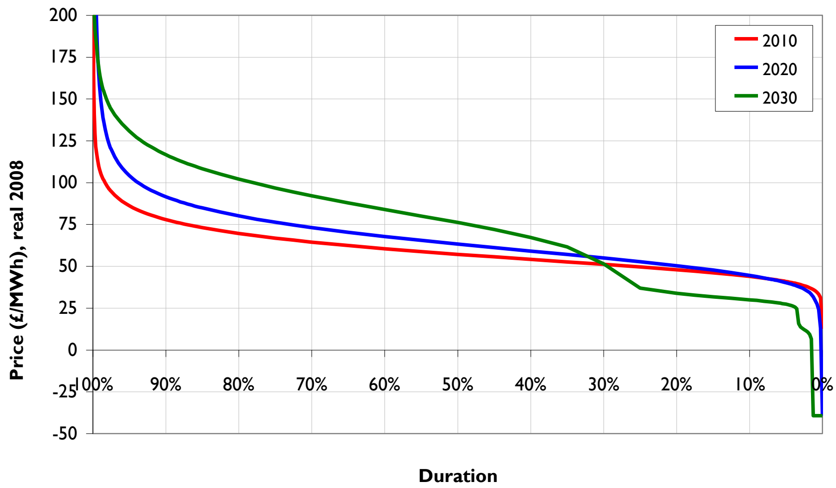
investment signals for low carbon generation will diminish in the future. This raises the question of where the price signals will come from to continue the decarbonisation of the electricity sector, and if market mechanisms are to continue to work the answer could lie on the demand side.

Price duration curves

Figure 9 shows the mean price duration curves[27] for 2010, 2020 and 2030 in the EFC scenario. There are significant differences between the three curves. Between the 0 and 30th percentiles (when renewables output is likely to be high) prices are lower in 2030 than in 2010 and 2020 due to higher output from low short run marginal generation cost plant during those periods. In 1.3 percent of periods (or approximately 110 hours of the year), prices are negative as supply from non-dispatchable generation (including wind and nuclear) exceeds demand: renewable generators would seek to recover the opportunity cost of forgone ROCs before turning down. We refer to the need to turn down non-dispatchable generation as 'spill[28]'.

Throughout the mid-merit (centre) and peak (left) part of the curve, prices are higher in 2030 than in 2009 due to the higher commodity prices in 2030, and in particular the high carbon price. Prices in 2030 rise above 500 £/MWh for a few hours of the year, reflecting tighter supply conditions when output from intermittent renewables is low. While the probability of lower prices, and indeed negative prices, will increase with increasing levels of intermittent generation, the occurrence of high peak prices is also likely to increase.

Figure 9 Price duration curves, 2010, 2020 and 2030, EFC scenario



The level of interconnection with other markets has an important influence on the shape of the price duration curves. Where power flows over interconnectors in response to price differentials between the GB market and connected markets, this will tend to have the effect of reducing peak prices and increasing offpeak prices. The lower the correlation in demand and renewables output in those markets with GB, the greater the potential effect. Where interconnectors become constrained and price differentials persist this can provide important investment signals for future investment in interconnection. Likewise a widening

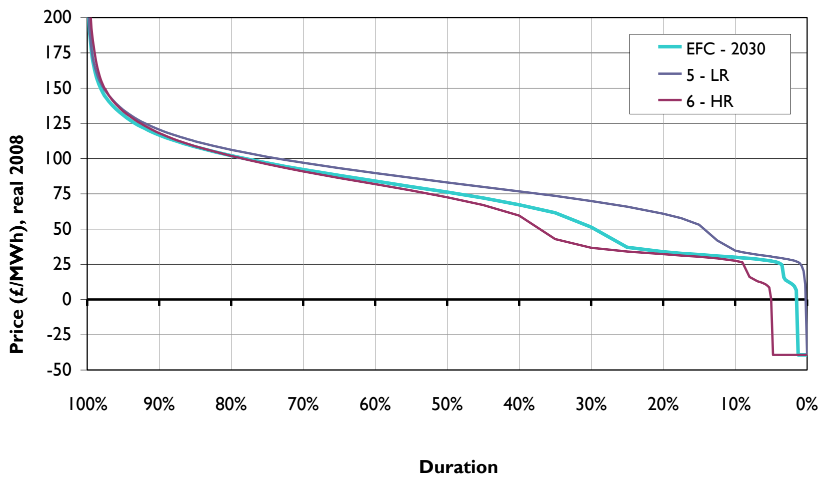
[27] The price duration curves shown are the mean of the (2000) simulated half-hourly prices in the year ordered them from highest on the left to lowest on the right.

[28] Spill is defined to occur when the output from inflexible renewable generation plus output from inflexible nuclear generation plus output from synchronised part-loaded capacity is greater than demand.

spread between peak and offpeak prices creates greater incentives to shift load (either permanently or dynamically in response to price signals) or invest in storage devices.

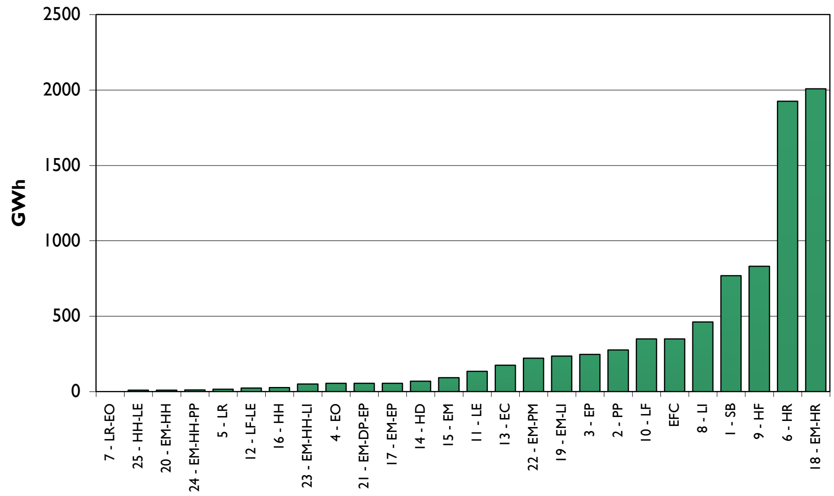
Greater interconnection and demand side response may be very important for accommodating higher proportions of renewable. For example, Figure 10 compares the mean price duration curves in 2030 under the High renewables (6-HR) sensitivity to the EFC scenario. Under this sensitivity negative prices occur in 5 percent of periods during the year, and the total spill of renewable generation is 2 TWh (or 1.8 percent of the total renewable generation). The lowering of baseload prices would likely deter other baseload investment, but we should expect companies to respond to the greater price spreads with greater investment in demand side response, storage and interconnection. Hence, security of supply need not necessarily be jeopardised.

Figure 10 Price duration curves, EFC, High and Low renewables



The spill volumes in 2030 across all the sensitivities is shown in Figure 11. Those sensitivities with the lowest spill (7-LR-EO, 25-HH-LE and 20-EM-HH) are those with the least volume of renewables and nuclear due to lower carbon prices or increased perception of risk for investors.

Figure 11 Expected spill in 2030 by sensitivity



4.2.2 Plant profitability

We now turn to examine what the impact of the changing profile of prices might be on the profitability of plant and the consequences for levels of investment. To do this we examine the gross margins of different types of plant. The gross margin is defined as: wholesale market revenues less variable generation costs and less annual fixed costs. Variable generation costs are fuel, carbon, non-fuel variable costs and fuel transportation costs. Annual fixed costs include transmission connection charges, salaries costs, insurance and plant maintenance costs.

It should be expected that the load factor of conventional thermal plant would decline over time as more efficient plant enter at baseload and displace them up the merit order. However, the rapid expansion of intermittent renewables will accelerate this load factor decline. If the decline in load factor cannot be compensated for by capturing higher peak prices, or through new opportunities to provide balancing services, such as frequency responses and reserve, to the System Operator, plant may be forced to close early. For new plant, flexibility will be a key value driver. Investment can still be attractive if plant can switch off during periods of very low (or negative) prices, and then earn sufficient revenues at other times to recover variable and fixed costs and earn a reasonable return on capital.

CCGT profitability

Figure 12 shows the annual load factors for an existing coal plant (which is fitted with FGD and SCR) as well as two representative new CCGT plant, one commissioned in 2009 (with an assumed 51.4% HHV efficiency) and one in 2026 (with an assumed 54.5% HHV efficiency). The commodity prices in the EFC scenario generally favour coal plant in the next decade before the carbon prices start to increase sharply. This is clearly seen in Figure 12, with the load factor of the existing coal plant being largely unaffected by the increasing intermittent generation. Running close to its annual availability until 2021, the load factor drops off very rapidly after 2022 and the plant retires in 2027. The CCGT commissioned in 2009 operates close to baseload initially but its load factor falls steadily from 2011 to just above 10 percent by 2030. The CCGT commissioned in 2026 can expect to run at between 40 percent and 50 percent load factor.

Figure 12 Average annual load factor of thermal plant

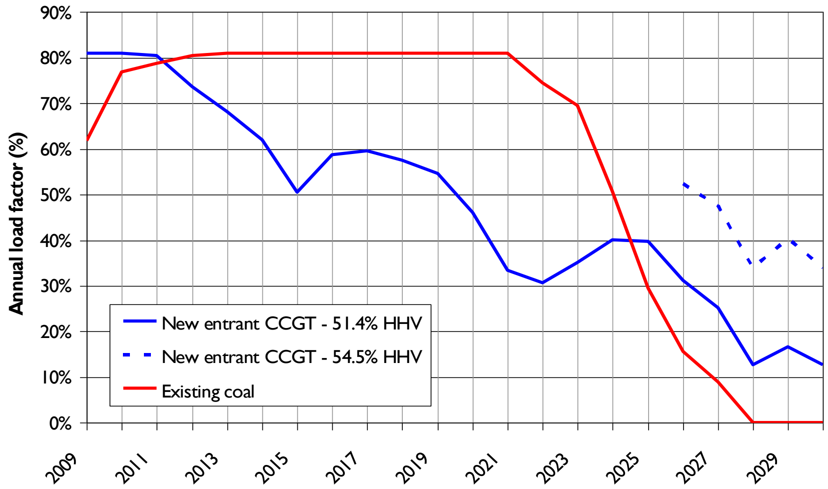
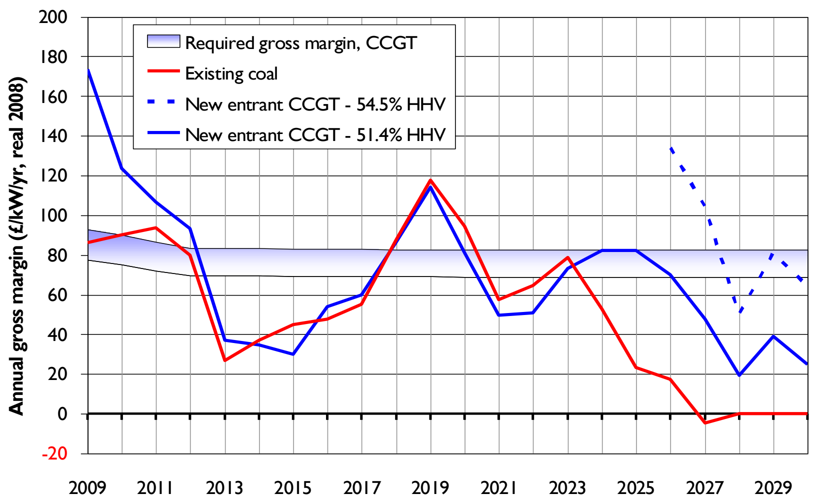


Figure 13 shows the annual gross margin in £/kW under the EFC scenario for our three thermal plant. The graph also shows an indicative range of gross margins for a new CCGT that would be required by different types of investor to cover their capital costs and make new investment attractive. The expected returns vary considerably but are sufficiently high to stimulate periods of investment in new CCGT through to 2026. After a hiatus in the second half of the next decade, 7.6 GW of new CCGT build occurs between 2020 and 2026. Over this period, the market price is generally being set by older less efficient CCGT plant. New CCGT has a significant efficiency advantage and with high carbon prices feeding into the electricity price, are able to earn significant infra-marginal rents. As the system efficiency continues to rise and more efficient plant and low marginal cost plant are setting prices, this opportunity diminishes. Load factor expectations become too low, and no further CCGT build is built after 2026 in the EFC scenario.

Figure 13 Gross margin of new entrant CCGT and conventional coal, EFC scenario



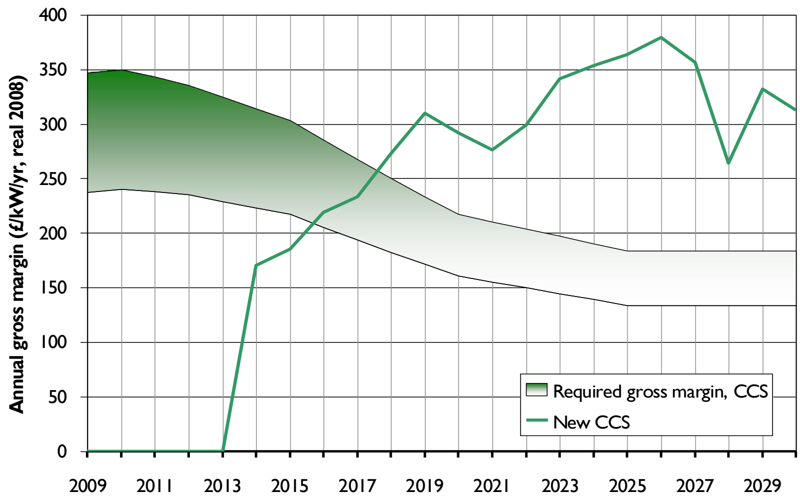
As should be expected, the profitability of CCGT plant is lowest in sensitivities with high renewables levels (6 – High renewables and 9 - High fossil fuel). In these cases, the depressing effect on prices of more low SRMC plant is not offset by peakier prices sufficiently to incentivise any significant increase in CCGT build over and above the EFC scenario. Rather the increased market share of wind plant has led to the more rapid retirement of existing plant: an additional 3.3 GW of existing CCGT in the High renewables case plant retire prior to 2030 relative to the EFC scenario.

In these cases there would be less flexible plant in the capacity mix, but also a greater requirement for it to manage the additional variability surrounding the greater volume of intermittent renewables. We discuss the issue of flexibility further below.

CCS profitability

By the mid-2020s coal plant fitted with CCS replaces CCGT plant as the least cost thermal plant. We have assumed in the EFC scenario that the technology is technically as well as economically proven by then, and with the carbon price on a steady upward trajectory, new build of CCS plant increases. By 2030, there is 6 GW of coal plant fitted with CCS on the system, with the first fully commercial plant having been commissioned in 2027. The gross margin of CCS plant, compared to the required return for different types of investor, is shown in Figure 14.

Figure 14 Gross margin of CCS, EFC scenario[29]



Renewable plant profitability

The annual profits for renewable plant[30] increase steadily in the EFC scenario, as electricity prices rise due to the increasing carbon prices.

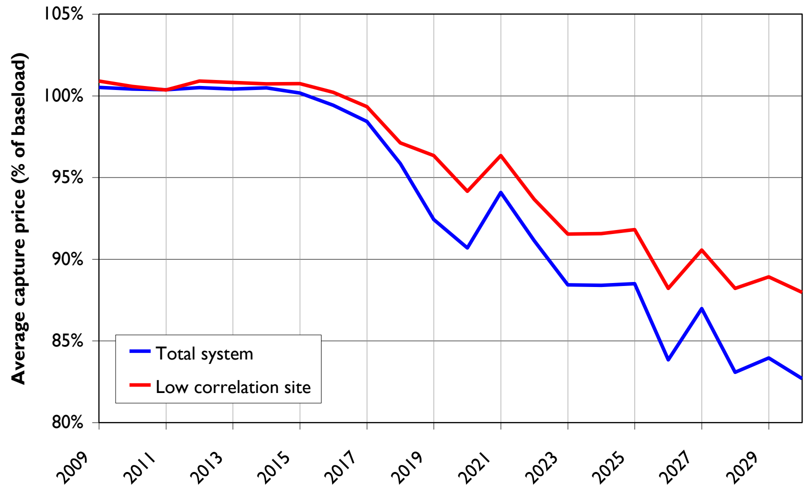
However wind plant in particular face downward pressure on their revenues as more wind is added to the system. Over time there will be an increasing relationship between market prices and output levels; market prices will be lowest when their output is highest. This effect is illustrated in Figure 15. It shows the capture price for wind plant as a percentage of the annual baseload price. In 2009, variations in wind

[29] Gross margin shown for the Demo CCS plant assumed to be commissioned in 2014. CCS is assumed to be technically proven post-2020, and hence despite being potentially highly profitable, it is not commercially developed until later in the 2020s.

[30] Notwithstanding that many renewables plant will have signed long term offtake agreements at fixed or indexed prices.

output have little impact on price and wind plant are able to capture close to the baseload price, or a little above since output is higher in the winter when prices are higher. Into the future the impact of wind on the market price steadily increases, and by 2030 wind plant are only able to capture 83 percent of the baseload price. Figure 15 also shows that a wind plant in a location geographically removed from the majority of wind plant could capture a better price since its output is less correlated with the periods of lower price. In this example, the plant is able to capture a price 5 percent higher than the average wind plant by 2030. However, it should be noted that these results are very dependent on assumptions on the levels of interconnection and demand side response.

Figure 15 Annual average system capture price of wind



The price capture results shown in Figure 15 do not take into account the cost of balancing risk. Balancing costs and the costs of constraints at the system level will likely increase significantly with the greater penetration of intermittent renewable. Depending on how these additional balancing and constraint costs[31] are targeted, there may be further downward pressure on the earnings of intermittent renewable in the future.

In the EFC scenario, the effect of increasing wholesale electricity prices offsets the effect of reducing price capture and balancing costs, and investment in wind continues. However, if electricity prices were not to rise, subsidies for certain types of renewables may need to increase to counter these effects.

Nuclear plant profitability

In the EFC scenario, investment in new nuclear plant looks attractive on the back of the high carbon prices (~120 €/t in 2030). By 2030, there is 11.2 GW of new nuclear plant on the system, and more would be possible if a higher maximum annual build rate is assumed. In the sensitivities with lower carbon price (50 €/t or lower) investment in new nuclear becomes more marginal. The sensitivities with high renewables output also put some downward pressure on nuclear plant profitability and slows the rate of investment in new capacity. Different assumptions of the capital costs of new nuclear would also have an impact on how much is built.

The EFC scenario provides a robust carbon price signal which makes investment in new nuclear look attractive. However, the success of the carbon price signal in bringing forward low carbon generation

[31] The additional balancing costs per MWh of intermittent renewables reach approximately 9 £/MWh by 2030. Assuming full pass through of these costs, rather than 50%, would therefore reduce the profitability of these plant by around 4.50 £/MWh. The proportion of balancing costs to which intermittent plant are exposed to will, depend on the details of the market design.

during the next two decades could in the longer run undermine future signals to invest in low carbon generation. As noted above the pass through of the carbon price into the electricity price will start to diminish as more and more low carbon generation sits on the margin. In the EFC scenario this starts to occur from the late 2020s. For investors in nuclear, and other plant types with long economic lifetimes, this is an important consideration.

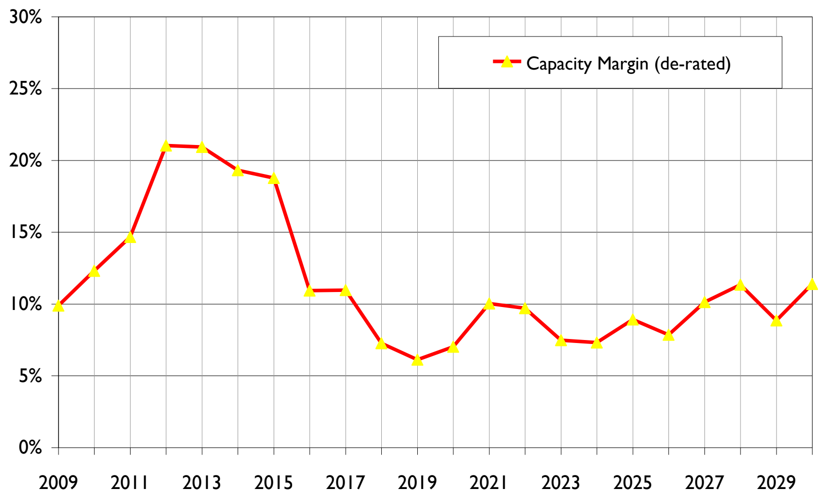
4.2.3 Implications of investment for security of supply

We now consider what the impact of plant profitability and strength of investment signals is on security of supply. In our model new investment will always occur, but the question is how tight the capacity margin needs to be to create sufficiently strong price signals to stimulate that investment. We examine the de-rated capacity margin in the EFC scenario, and estimate the risk of energy unserved (firm demand not being met).

De-rated capacity margins

The de-rated capacity margin for the EFC scenario is shown in Figure 16[32]. The de-rated capacity margin fluctuates according to new build, plant retirement and demand changes. The changes in the de-rated margin in the near-term reflect the committed build decisions and known retirements (largely due to the LCPD and planned nuclear decommissioning). After 2020 the de-rated capacity margin remains within the range of between 6 percent to 11 percent through to 2030.

Figure 16 De-rated capacity margin, EFC scenario



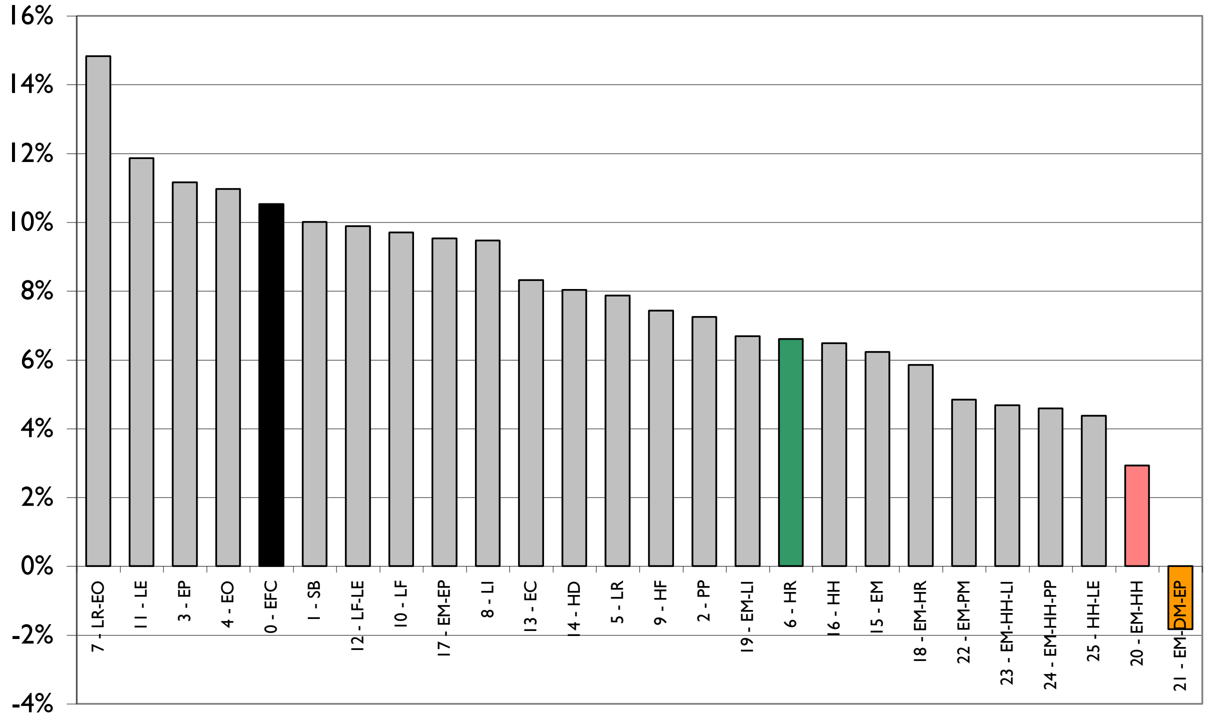
The de-rated capacity margins averaged[33] across 2028 – 2030 across all sensitivities are shown in Figure 17. There are four sensitivities where the de-rated capacity margin is on average higher than in the EFC scenarios. These are the cases where we have flatter demand profiles due to greater electrification of heat and transport. Under the other sensitivities we see lower de-rated capacity margins on average than in the EFC scenario. The sensitivities that lead to the lowest de-rated capacity margins were those where companies delay their investment decisions either because of risk aversion (higher cost of capital) or

[32] Refer to section A.3.3 for a more detailed discussion on the de-rated capacity margin in the EFC scenario.

[33] We present the results averaged to eliminate year-on-year fluctuations which are specific to individual retirement decisions.

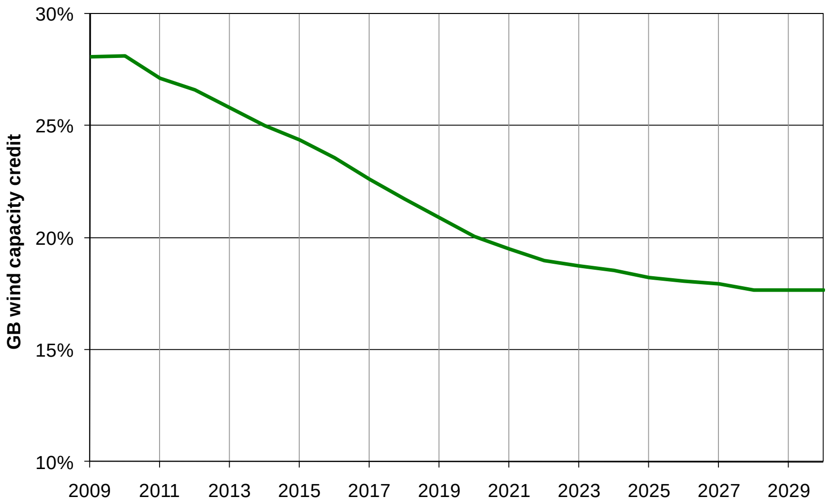
because of taking a short term view. In these cases, the de-rated capacity margin has to fall further, and expected prices rise higher, before investors act.

Figure 17 De-rated capacity margins by sensitivity



The average de-rated capacity margin includes a 'capacity-credit' for wind plant which is a measure of their average contribution to security of supply. It is calculated using stochastic techniques to find the volume of thermal plant that provides an equivalent impact on security of supply (as measured by the risk of energy unserved) as each MW of wind capacity is added to the system. Figure 18 shows the evolution of the wind capacity credit in the EFC scenario.

Figure 18 Capacity credit of wind plant

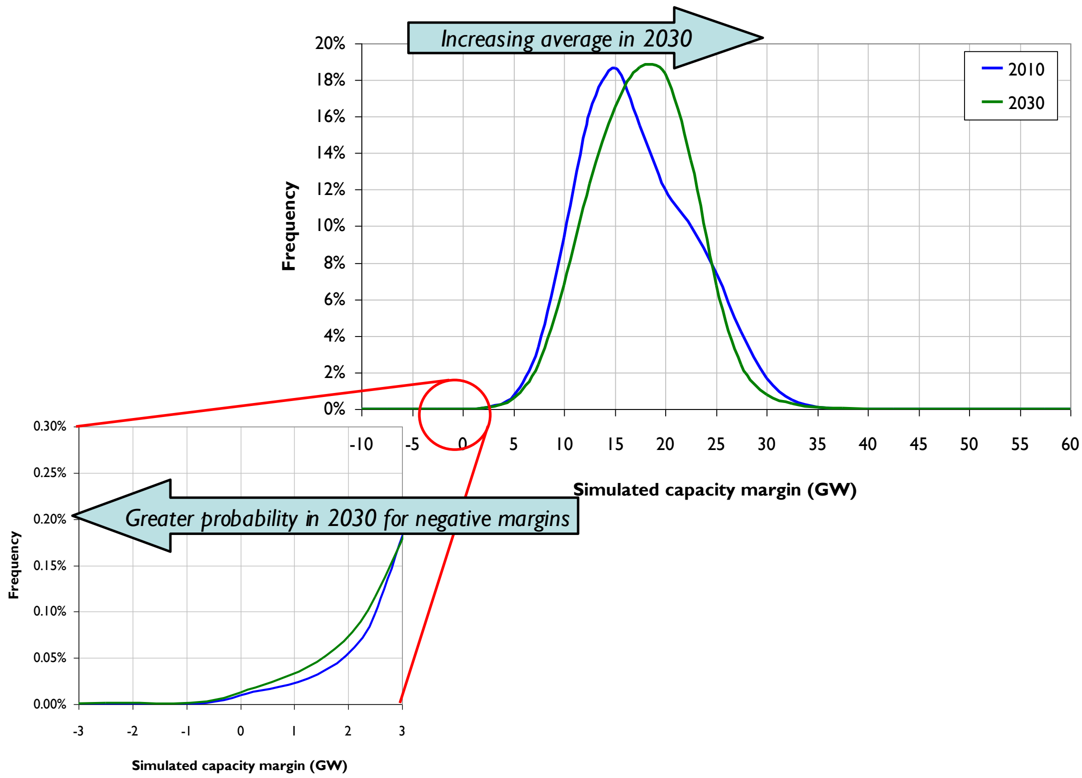


In 2009, the capacity credit is around 28 percent, which is roughly the same as the average annual availability of wind plant on the system. However, as output from wind plant is likely to be highly correlated and the risk of a loss of a large portion of supply increases with more wind on the system, there is a downward trend in the capacity credit. By 2030, the capacity credit declines to just under 18 percent. In our modelling, we assume that companies factor in this declining capacity credit for wind in making their investment and retirement decisions. In other words, they are anticipating there will be more frequent periods of high prices when wind output across the country is low.

The de-rated capacity margin provides a useful indicator of security of supply. However, the outturn distribution of capacity margins in each period can be very different in two years with the same de-rated capacity margin. In Figure 19, we show the distribution of half-hourly capacity margins[34] for 2010 and 2030 for the EFC scenario. As the level of renewables on the system increases from 8.9 to 36.5 percent, the capacity margin increases on average (the mean of the green distribution is to the right of the blue one). It is only at the far left of the distribution (shown in the inset) that there is a small increase in the probability of very low (in this case negative) margins.

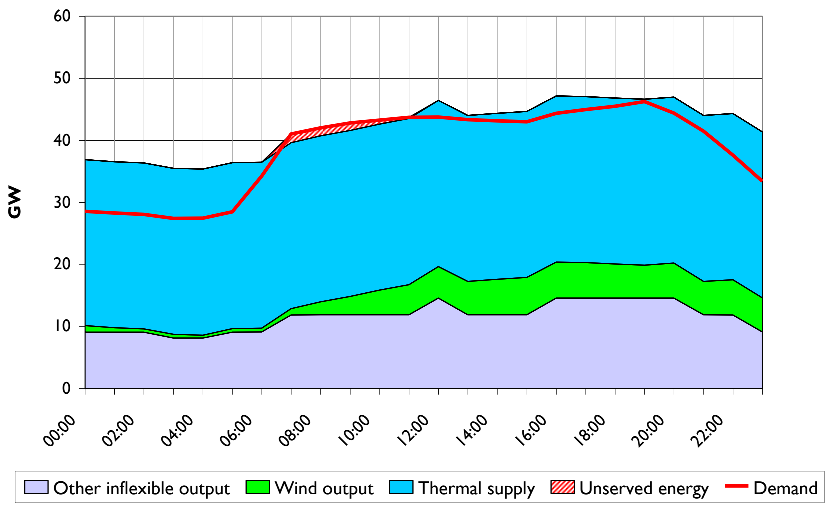
[34] These are outturn capacity margins based on simulation of demand, outages and renewables output.

Figure 19 Distribution of outturn capacity margins, 2010 and 2030, EFC scenario



To illustrate what a negative capacity might mean we show the results of a simulation for a particular day in Figure 20 from the EFC scenario. It shows an extreme outcome with a period of very low wind output coinciding with a very high demand day.

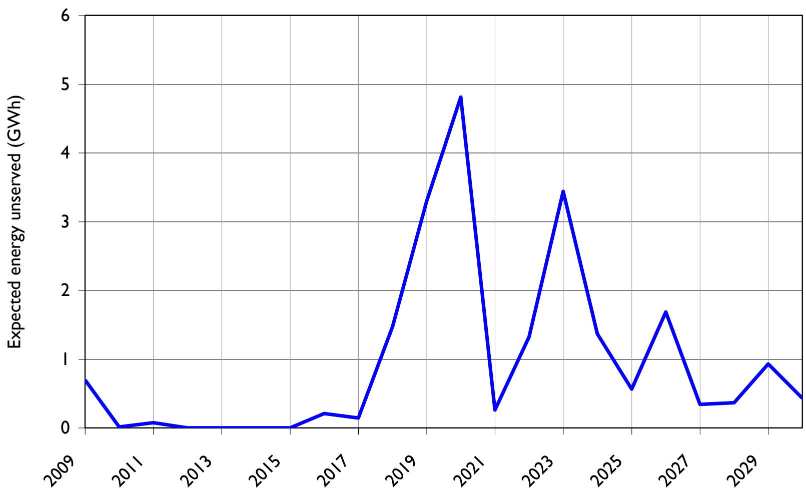
Figure 20 Extreme winter day with limited wind output, 2030, EFC scenario



In this simulation all plant that is available is generating through much of the day, and there is load shedding from large industrial consumers. However, between 07:00 and 11:00 there is insufficient demand to meet supply and some demand is unserved. At its peak, this amounts to 3 percent of total demand. This could potentially be managed if there was greater demand side response on the system by this time (for example enabled by smart meters and smart appliances), or in extremis by lowering the system voltage for short periods.

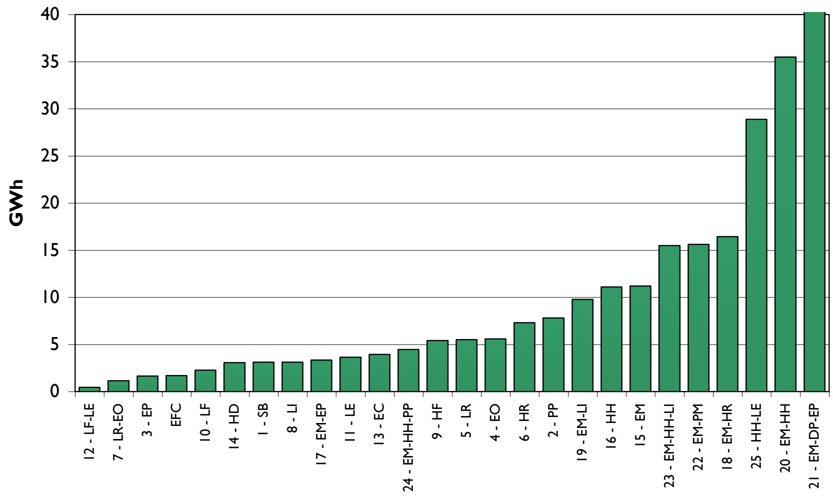
The total expected energy unserved for each year in the EFC scenario is shown in Figure 21. The level of expected energy unserved remains low until 2017 and then increases somewhat, peaking in 2020 at approximately 5 GWh. This is of a similar magnitude to energy unserved resulting from transmission and distribution failures each year.

Figure 21 Annual expected energy unserved, EFC scenario



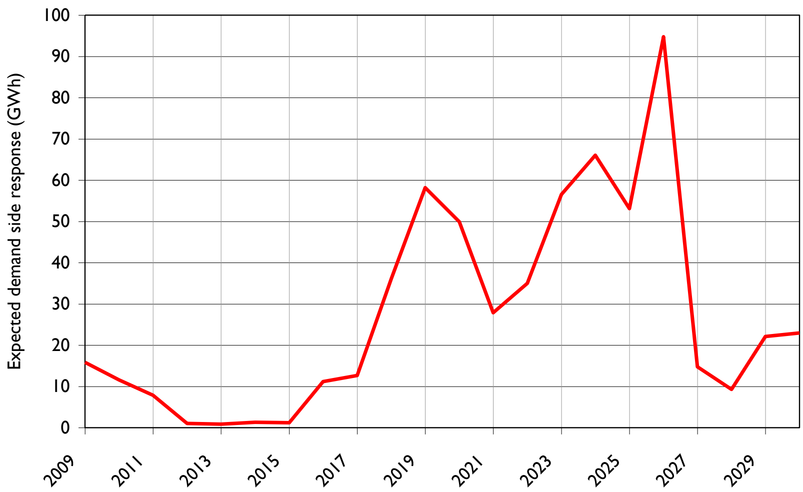
In Figure 22 we show the highest occurrence of annual expected energy unserved for the period 2026 - 2030 in each sensitivity. Those sensitivities that have the lowest de-rated capacity margins have the highest risk of energy unserved, with the greatest being 423 GWh in the sensitivity with lack of foresight of both demand growth and rising EUA prices, combined with an increase in demand from electrification (21-EM-DP-EP). These levels of energy unserved are more material, but again could potentially be managed with greater response on the demand side (or greater interconnection).

Figure 22 Maximum expected energy unserved, 2026 – 2030, by sensitivity[35]



In the EFC scenario we have assumed that the majority of demand side response comes from large industrial consumers. Figure 23 shows the expected volumes of demand side response in each year of the EFC scenario.

Figure 23 Expected demand side response from large industrial consumers



[35] The graph is curtailed at 40 GWh per annum. In the EUA myopia, Demand myopia, Transport and heat electrification, all periods sensitivity the maximum energy unserved is 423 GWh per annum.

4.3 Flexibility

As well as the total capacity on the system, the mix of different plant types will be an important element in ensuring security of supply. In particular, the variability of wind output will increase the demands on flexible thermal plant in balancing the system.

At this stage it is unclear what volumes of flexible plant will be required, what types of plant will be able to deliver it, the costs involved, and whether the current market arrangements will lead to the investment needed. This presents a potential barrier to the full decarbonisation of the electricity sector, since there are currently few low carbon options that can provide such flexibility economically. Whilst plant fitted with carbon capture and storage (CCS) or biomass plant may be able to provide this role in the longer term, there is a risk that in the shorter term additional gas plant will be built which will make future decarbonisation more difficult.

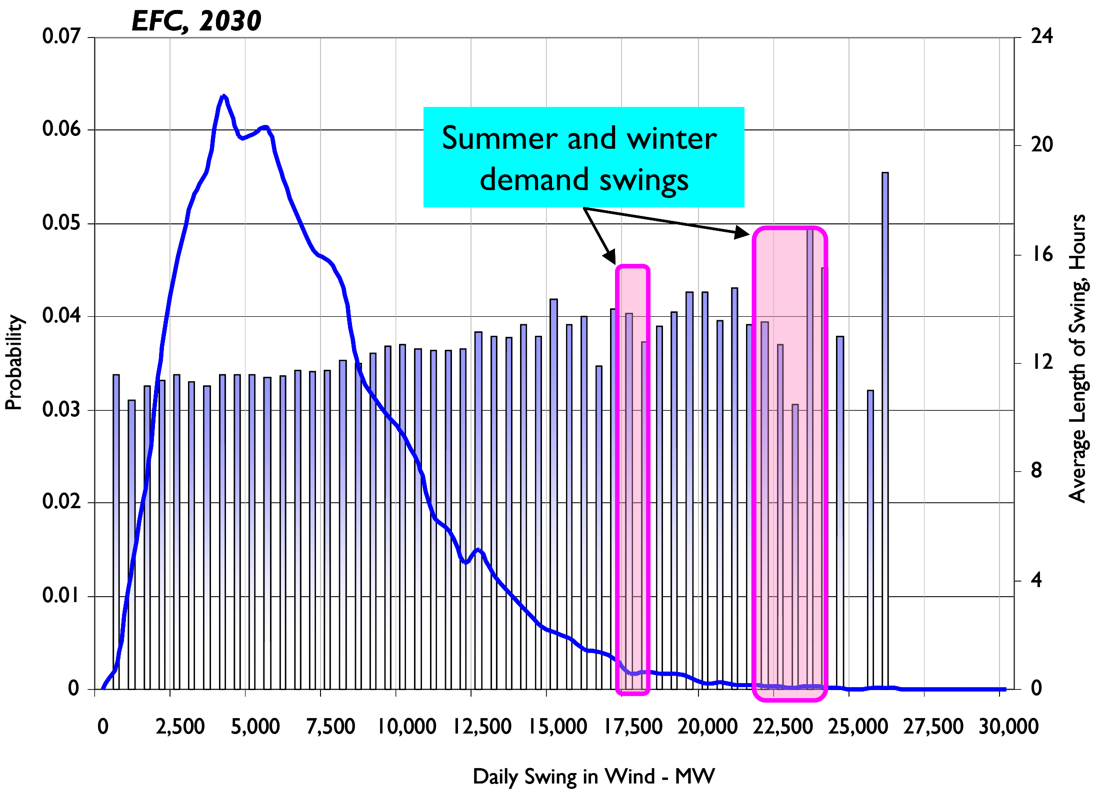
Beyond questions surrounding whether flexible plant will be available, there is uncertainty as to whether there will be sufficient within-day liquidity to ensure that it gets 'dispatched' efficiently, or whether the system operator will need to take a greater role. Similarly, with the operational requirements of the system changing, there is concern that the current market arrangements will not deliver the necessary and appropriate type of investment.

To explore these issues further we present further detailed results from modelling 2030 in the EFC scenario. We look at the within day swings in wind output ("wind swings"), the operating profiles required from thermal plant to manage variations in demand and wind output, and issues surrounding wind forecast uncertainty.

4.3.1 Wind swing

In Figure 24, we show the distribution (blue line) of maximum daily wind swings in 2030 under the EFC scenario (both up and down). These are defined as the difference between the highest and lowest level of wind output in the day. Also shown (as bars) is the average time elapsed between the point of highest and lowest output.

Figure 24 Distribution of simulated daily wind swings in 2030, EFC scenario



In 2030, the mean daily maximum wind swing is estimated to be 5.7 GW and occurs, on average over approximately 12 hours. Although, as expected, the larger maximum daily wind swings do tend to occur over longer periods, the difference is quite small. For example, a wind swing of 12 GW in length occurs on average over 13 hours while one 20 GW in length occurs on average over 15 hours. These wind swings compare to demand swings of approximately 25 GW in the winter over a 13 hour period, and 18 GW in the summer over a period of 7 hours.

In the High renewables case, when there is 37.6 GW of wind capacity compared to 28.6 GW in the EFC scenario, the average daily maximum wind swing increases by 2.3 GW to 8 GW while the most extreme swing increases from 21 GW to 28 GW.

4.3.2 Thermal ramping

We now explore whether the flexibility of plant on the system in 2030 under the EFC scenario is sufficient to manage the variations in demand and wind output. We assume that most of the flexibility on the demand side is provided by CCGTs by 2030 since all existing coal plant will have closed, and coal planted fitted with CCS will mainly be running baseload.

To do the analysis, we first examine the ramping capabilities of the current CCGT fleet, as depicted in Figure 25. The chart shows the ability of the current CCGT and CHP fleet to ramp from cold based on plant dynamic data submitted to Elexon for 2008[36]. It should be noted that gas plant would not normally be

[36] This data includes notice to deviate from zero and ramp rates, which are aggregated and averaged for each plant to calculate the maximum amount of energy each plant could provide within each hour if the plant were starting from cold. For example, suppose a 600 MW CCGT plant

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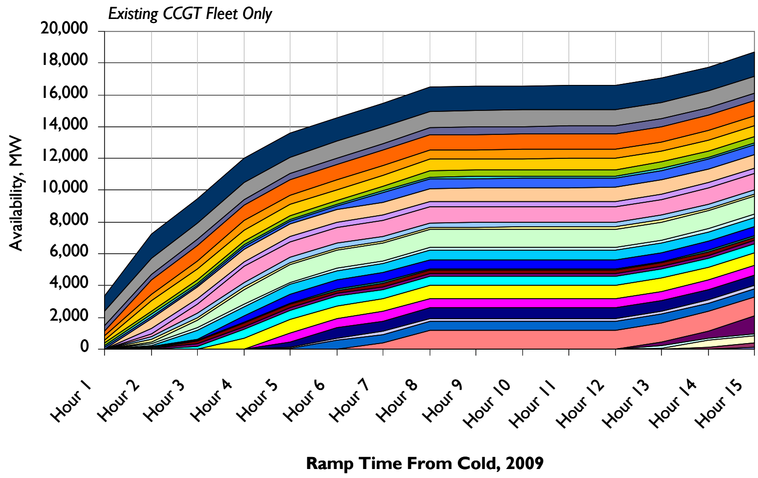
operated in this way, and this data represents the maximum ramp rate theoretically achievable. Each color represents a different plant.

Figure 25 Ramp time from cold of the existing CCGT fleet



Based on this data, if the 18.7 GW of de-rated[37] CCGT capacity were all sitting cold, approximately 3.2 GW could theoretically be available after one hour. By the end of the second hour, availability increases to 7.2 GW and, by the end of the fourth hour, is 12 GW. Nearly 90 percent of the capacity can be made available in 8 hours and all within 15 hours.

Next, we assume that all newly built CCGT plant is at least as flexible as those from the current fleet remaining in 2030. This is a reasonable assumption to make given that new CCGT plant are being designed to two-shift and respond flexibly, whereas many early generation CCGT plant were developed on the assumption that they would operate baseload. In Figure 26, we show the corresponding ramp capability as the red area, added to that of the (blue) existing plant.

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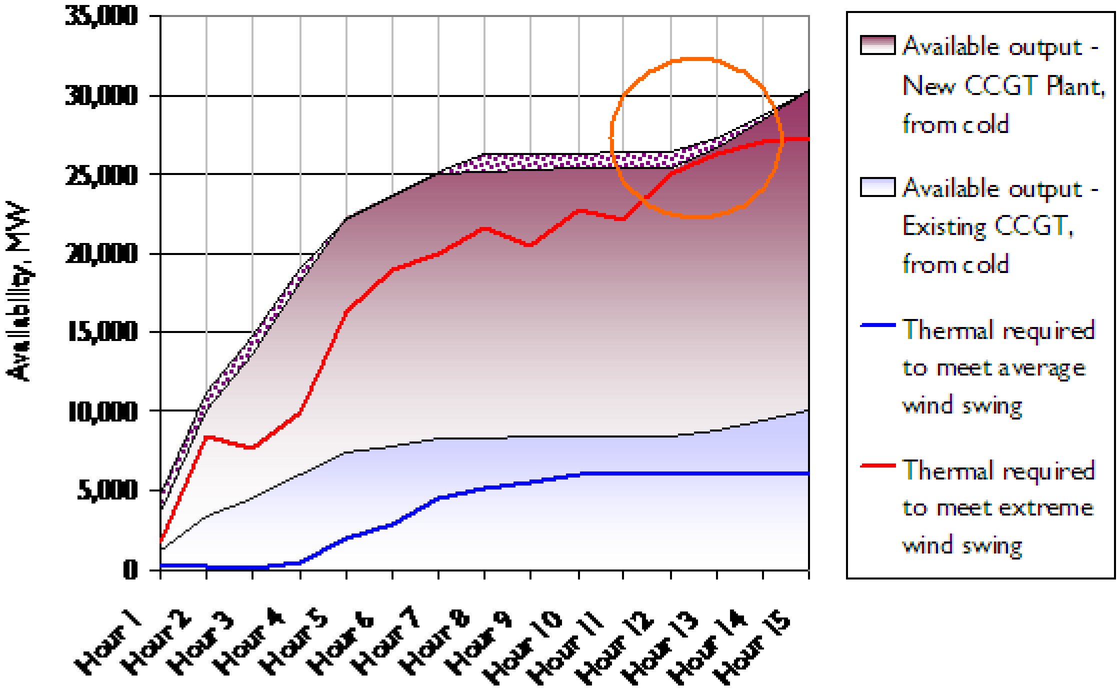
requires 1 hour's notice to deviate from zero, after which it is able to ramp at a rate of 10 MW/minute. This plant would thus be specified as able to provide no MWs by the close of the first hour and 600 MW (10 MW/minutes multiplied by 60 minutes) by the close of the second hour. These ramp rates have been derated to account for plant not always being available and / or tripping on start up. Of the existing 25 GW of CCGT plant, data was available for only 23 GW, which derated equates to 18.7 GW.

[37] We have de-rated the capacities to reflect the probability that at any one time, some plant will be unavailable due to maintenance or forced outages.

Figure 26 Ramping capability of 2030 CCGT fleet, EFC scenario



Overlaid on this chart are extreme wind swing (the red line) and a typical daily wind swing (the blue line). If all CCGT plant could be brought on from cold with the response times indicated by the Elexon data, the extreme swing in wind could just be met. The red circle highlights where the margin is tightest, just 236 MW in hour 13. In this simple illustration, we have not attempted to include the impact of reserve. By maintaining some proportion of capacity in a warm state[38], which is a realistic assumption, this will enable a faster initial ramping, but would reduce the maximum swing capability. In reality, for the extreme wind swing example it would probably be necessary to constrain off some wind output (particularly if the drop off could be forecast), or utilise some demand side response in order to manage the swing.

It is also interesting to note what happens to the capacity margins if there is a slight improvement in the flexibility of new CCGT. In Figure 26 this "additional" flexibility is depicted as the purple dotted area above the available output of new CCGT plant. In hours 12 and 13 of the swing, the margin is now over 1 GW. Thus, small changes in the assumed flexibility of the system can be material in terms of security of supply, highlighting that the "right" kind of capacity must be built if the system is to accommodate increasing levels of wind.

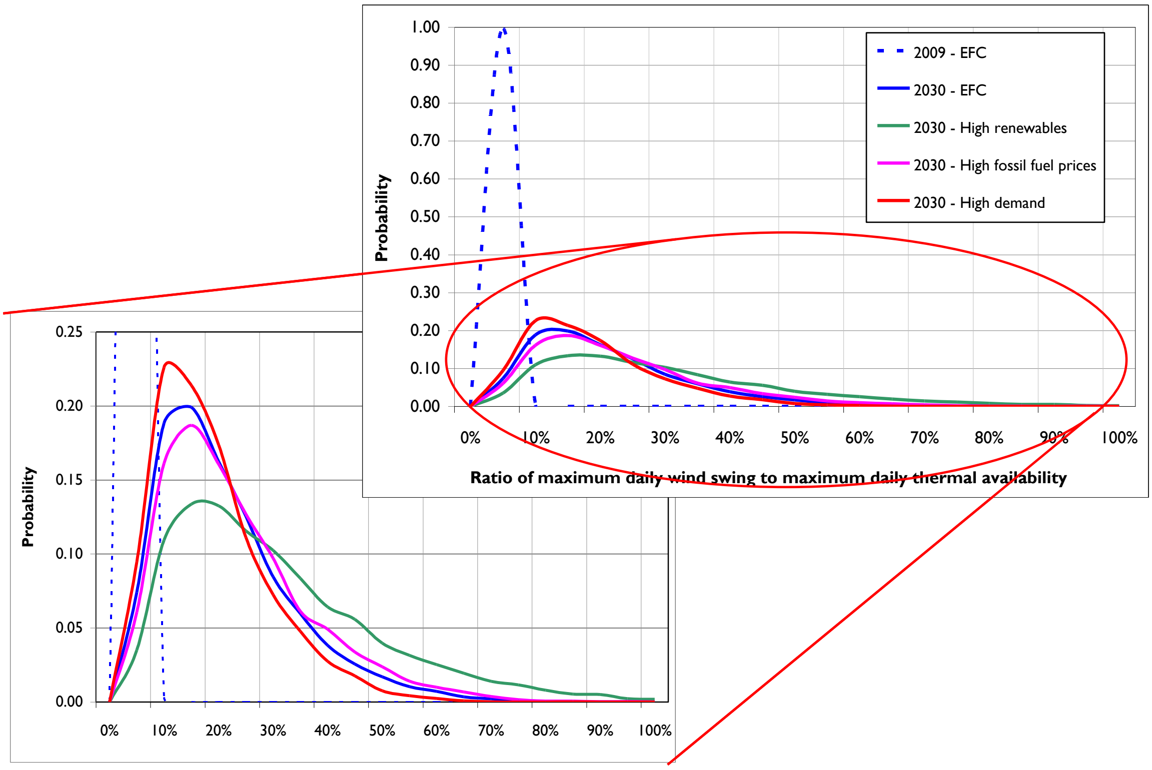
Figure 27 plots the distribution of the maximum within-day changes in thermal plant utilisation (including all thermal plant, not just gas-fired plant) in 2009, and in 2030 under the EFC scenario and other selected sensitivities. Maximum changes in thermal plant utilisation are calculated as the ratio of maximum daily wind swing to maximum thermal plant availability. Note this does not consider the impact of changes in demand as well. We examine this further below.

In 2009, the average ratio between the maximum swing in wind output and available thermal capacity is 5 percent, and never exceeds 10 percent. By 2030, the average is 15-25 percent, with the ratio in some

[38] Part-loading of plant for reserve is included in our daily market simulations See section C.1f or a more detailed description of part loading.

cases extending beyond 100 percent for the high renewable sensitivities. In these extreme cases there would not be sufficient flexibility from thermal plant to balance the system and a greater response on the demand side or through interconnectors would be necessary.

Figure 27 Ratio of maximum daily wind swing to maximum daily thermal availability, select sensitivities



4.3.3 Combining wind swings and changes in demand

So far we have looked at wind swing alone. In this section we examine wind swings combined with the daily change in demand to analyse the overall swing requirements from thermal plant. This leads to more extreme outcomes than wind swing alone.

In Figure 28 we show the results from one simulation which has a very large change in wind output during the day. Overnight output from wind plant reaches 90 percent of maximum capacity with the result that there is too much supply from non-dispatchable plant to meet the low overnight demand and up to 2 GW is spilled (probably managed by "constraining off" some wind plant). As the day progresses, output from wind plant falls significantly at the same time as demand rises. By the evening demand peak, output from wind plant is 1.5 GW compared to 26 GW at the beginning of the day. This wind swing requires flexible thermal to fill a gap of 24.5 GW within 15 hours. Over the same period demand rises by 18 GW, meaning that the total swing requirement from thermal plant is 42.5 GW.

Figure 28 Simulated winter day, 2030, EFC scenario

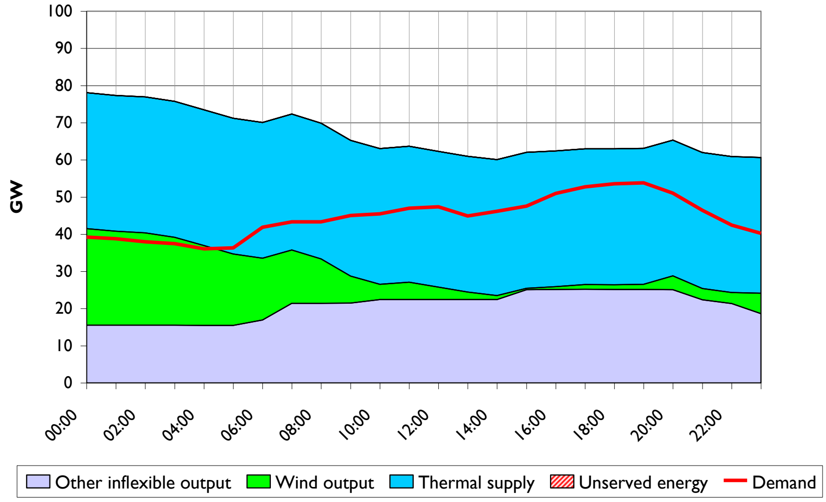
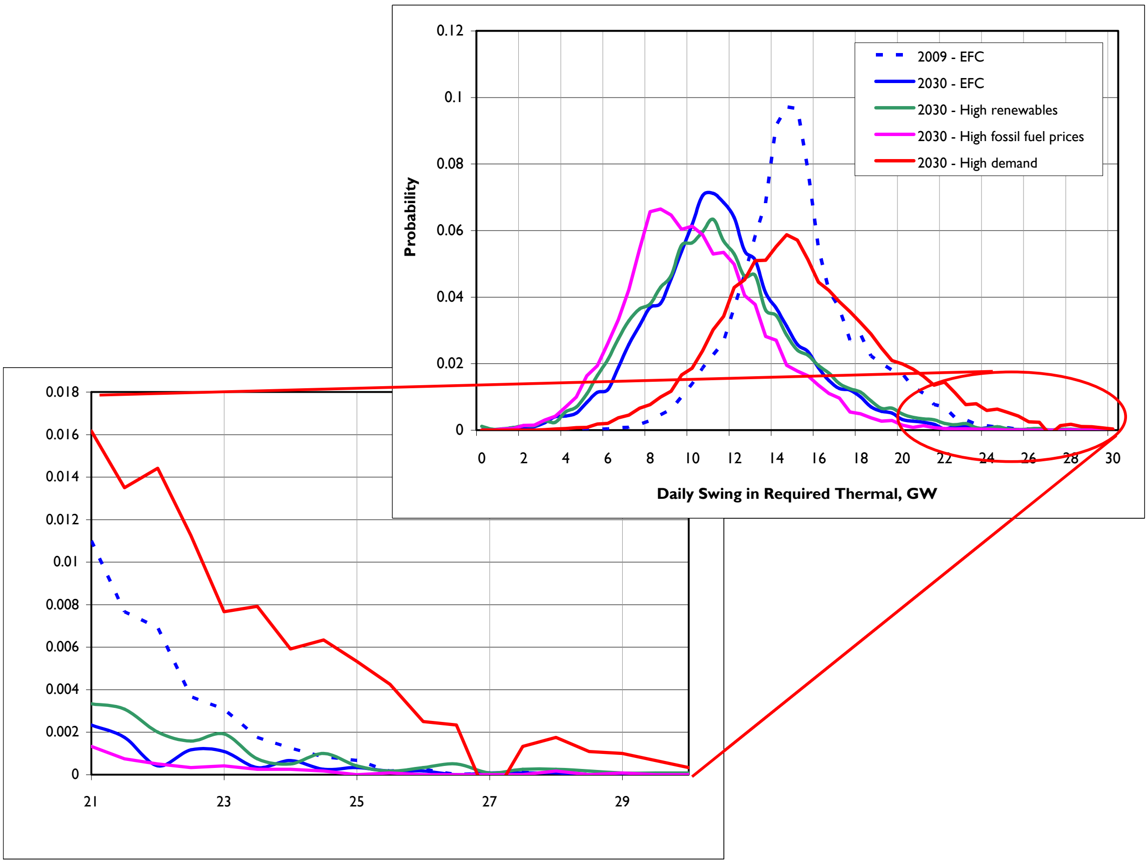


Figure 28 shows that the greatest requirement for flexibility from thermal capacity would occur if a rapid drop off in wind output coincided with the morning demand ramp. However, there is a tendency for the output from wind plant to be higher during the day than in the night, which can help to reduce the requirement for flexibility from thermal plant. The analysis in the previous section looked at the wind swings alone, but if we combine it with demand swings we see that the requirement for flexibility from thermal capacity in the most extreme cases is greater, but on average the requirement is slightly lower.

To illustrate this, we show in Figure 29 the distributions of changes in output required from thermal plant for certain sensitivities, taking into account demand swings. These are calculated by subtracting the output from wind and other non-dispatchable plant from the demand profiles, and assuming that thermal capacity must meet the residual shapes.

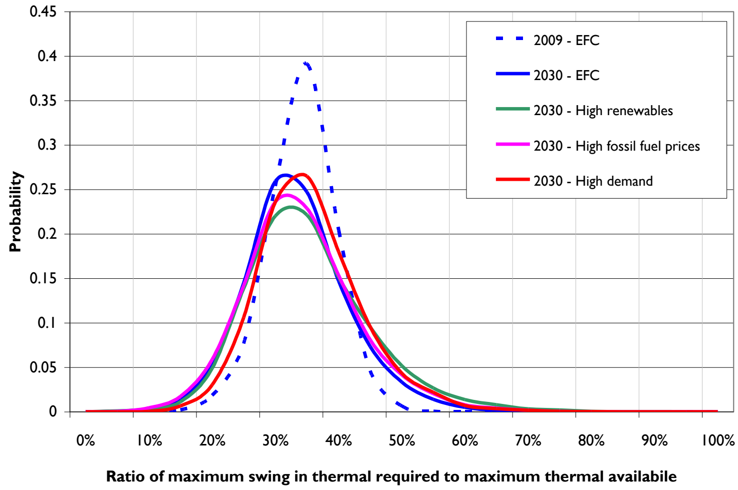
Figure 29 Daily change in output required from thermal plant, selected sensitivities



This shows that for the EFC scenario the mean maximum daily change in output required from thermal plant is actually lower in 2030 than in 2009, helped by generally lower demand, but that the tail of the distribution is longer. In the High demand case (sensitivity 14-HD) there is a greater occurrence of very high swings, although this will critically depend on the distribution of this additional demand through the day and how responsive it is.

Figure 30 plots the distribution of the maximum within day changes in thermal plant utilisation as in Figure 27 for selected sensitivities, but this time combining swings in demand with swings in wind output.

Figure 30 **Ratio of maximum swing in thermal required to maximum daily thermal availability, selected sensitivities**



Although the average maximum within day change in thermal utilisation is decreased, there are more cases when a very high proportion of the available flexibility is needed. In 2009, on one day in the year the ratio of the maximum within day change in thermal utilisation to thermal available exceeds 46 percent. By 2030, this ratio is exceeded on 18 days in the year. In the High renewables sensitivity (sensitivity 6-HR), this ratio is exceeded on 40 days in 2030. In the High renewables case there is less flexible plant on the system despite an increased need.

The analysis suggests therefore that there will be greater demands on thermal plant to operate more flexibly in the future.

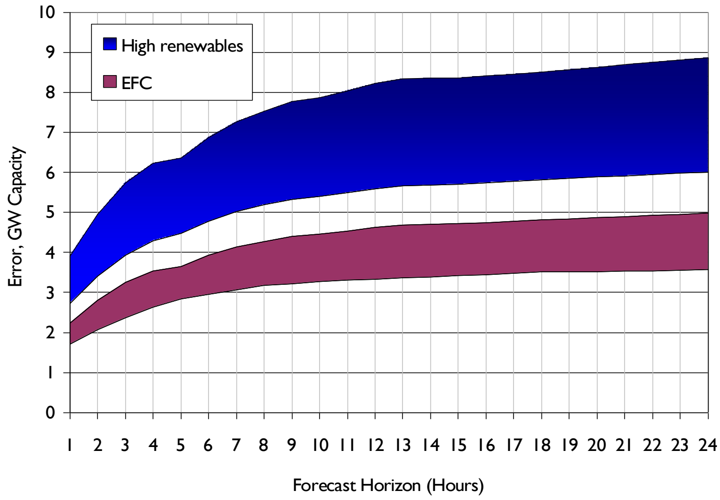
4.3.4 Wind forecast uncertainty

Up to now, we have analysed outturn swings in demand and wind output, ignoring forecast uncertainty. Although the ability to forecast wind has improved, and will likely continue to do so, there will still be uncertainty close to real-time. According to analysis conducted by Garrard Hassan[39], forecast error currently ranges from approximately 13 – 18 percent 48 hours out, a range which shows relatively little change until nearly four to six hours out. It is in this near-term range that forecast error begins to fall significantly. Six hours out, the forecast error is around 10 – 13 percent, three hours out 8 – 11 percent, and, by one hour out, is 6 to 8 percent.

If we simply apply these forecast errors to the full wind capacity in the EFC scenario and High renewables sensitivity we get the forecast errors shown in Figure 31. This represents the maximum forecast error since at any particular time output from wind is likely to be below full capacity.

[39] Source: Garrard Hassan, Forecaster Accuracy

Figure 31 Forecast error on wind capacity



Given the potential for the wind forecast error to be quite substantial, thermal plant will need to be responsive as well as flexible. For example, in the EFC scenario, on a day of high wind output the forecast error could be as much as 1.5 GW four hours out. This figure rises to 3 GW in the High renewables sensitivity.

Figure 32 shows the distribution of forecast errors 1, 2, 4 and 6 hours out on a day of high wind output in 2030 under the EFC scenario.

Figure 32 Distribution of forecast errors on wind output

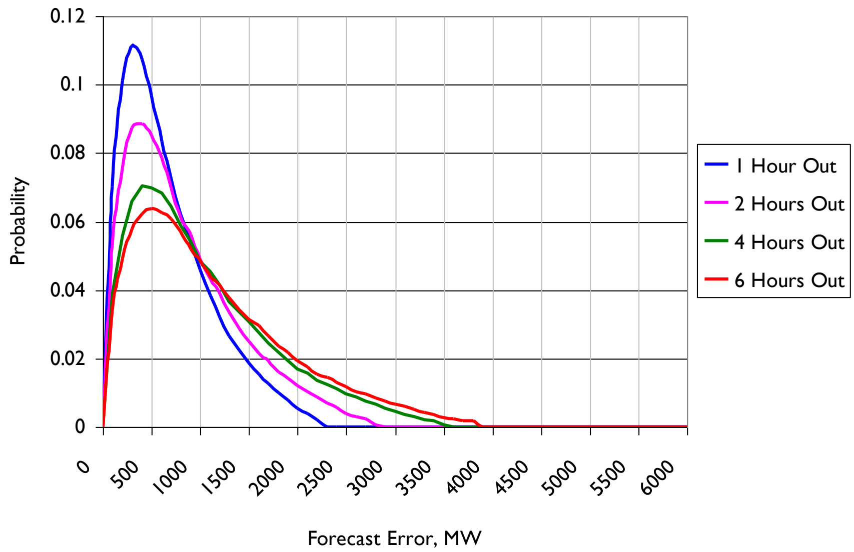
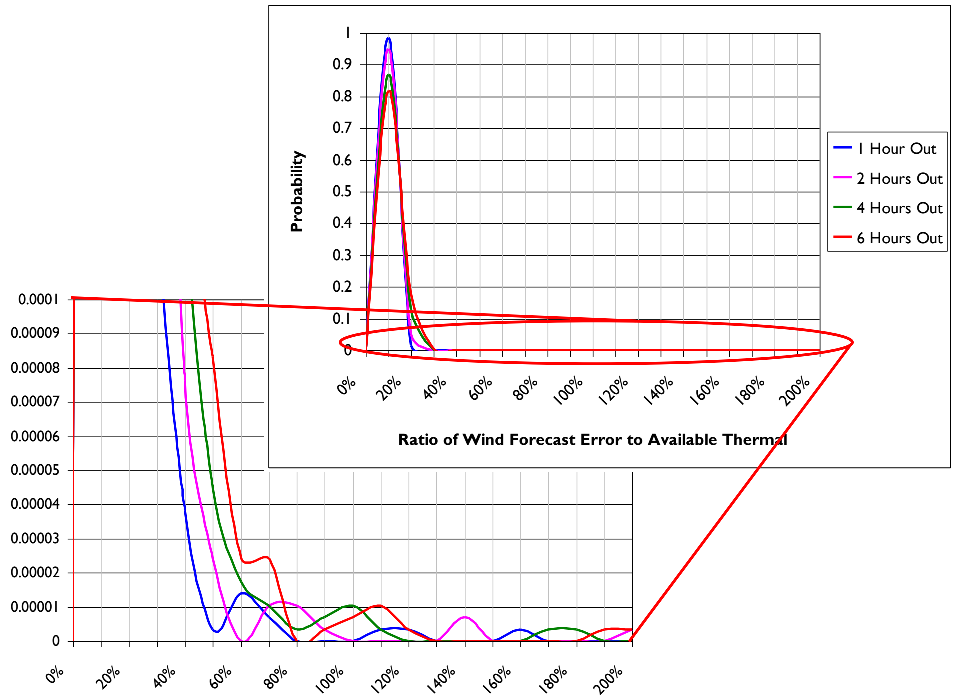


Figure 33 shows the distribution of these forecast errors relative to uncommitted thermal capacity (capacity that is not already generating or assumed being held as reserve). As shown by the steep peaks centred around 10 percent, there is enough spare thermal capacity available, although a greater amount of that plant would need to be warmed to be able to react at short notice. There are, however, occasions as shown in the inset, where there is insufficient spare thermal plant to cover the forecast error (occurrences above 100 percent), even if it were fully warmed.

Figure 33 Ratio of wind forecast error to available thermal



4.3.5 Summary

In summary the analysis suggests that thermal plant will need to operate far more flexibly in the future to manage variations in wind output. There will be occasions when very large swings in output from thermal plant would be required, and probably at the limit of the technical capabilities on the plant. Also, more plant would need to be held in reserve to manage wind forecast errors, although this needs to be considered in the context of the total amount of reserve required to cover other uncertainties.

Further investment in thermal plant is likely to be required, since not all plant are designed to operate in a flexible mode, and it may be necessary to constrain off renewables plant (transmission congestion aside) at times to help manage the within-day variations. Constraining off renewables, and part-loading thermal plant (running at low efficiency) would be detrimental to carbon dioxide emissions. Demand side response could play a very important role in providing flexibility and responsiveness, and with less negative impact on emissions.

5 Market arrangements

5.1 Introduction

In the previous section, we examined how the system in 2030 operates within our modelling framework. In this section, we explore qualitatively whether there are any potential issues in the current market arrangements that might pose barriers to the development and functioning of the system as envisaged.

We consider the following areas:

- dispatch and balancing;
- incentivising capacity and flexibility; *and*
- locational issues.

For each we briefly summarise current arrangements, identify potential issues, and then consider a range of possible future developments with regard to changes in arrangements going forward. In some cases (such as the sensitivity to investor decisions of new capacity build) our modelling results provide helpful insights; other areas (such as locational issues) were not a part of this modelling exercise and are considered purely qualitatively.

There can be no doubt that market arrangements and structure will change over the next 20 years. The same timeframe historically saw the vertical breakup of the CEGB[40], the accompanying privatisation of the sector, re-integration through mergers and acquisitions, the introduction of the England & Wales Pool, and its replacement with NETA[41] (and then BETTA[42]). The most appropriate changes to support a radical decarbonisation of the sector through to 2030 and beyond will require much deeper consideration, and thinking will no doubt evolve as time progresses, experience builds, and new issues emerge. Here we aim simply to summarise issues that are currently apparent and draw on thinking from GB and other markets in terms of initial changes that could be considered.

5.2 Dispatch and balancing

5.2.1 Current arrangements

Under BETTA, generators operate under the principle of self-dispatch. Counterparties contract for physical power via forward markets (from day-ahead to seasons or years ahead) using standard terms or structured agreements. Contracted positions can be changed up until 'gate closure', one hour before each half-hourly settlement period. Parties inform the central market operator, Elexon, of their contracted positions, and National Grid of their planned generation schedules. Where participants have an out-of-balance position (across their contracted position, generation output and customer demand), they are 'cashed-out', a mechanism by which the net position is deemed to have been bought or sold at calculated imbalance prices. These prices are intended to reflect the costs incurred by the SO to resolve residual system imbalances.

[40] Central Electricity Generating Board

[41] New Electricity Trading Arrangements

[42] British Electricity Trading and Transmission Arrangements

The primary tool that the SO has to balance the system is the Balancing Mechanism, within which it can accept offers and bids (pay as bid) from generators to turn up or turn down output (and also accept offers from large consumers to reduce consumption). The imbalance price used to cash-out imbalance positions that contributed to the overall system imbalance are set using an algorithm based on the prices of the accepted Balancing Mechanism bids and offers. For imbalance positions that reduced the overall system imbalance, a price (the Market Index Price, MIP) is derived from the APX half-hourly exchange. The arrangements have led to significant volatility in imbalance prices, and a wide spread between these and those observed in the within-day market.

The SO also contracts for certain balancing services in advance, either for services that cannot be easily delivered through the Balancing Mechanism, for example fast reserve, or where it deems it more economic to contract forward. The SO is incentivised to reduce its costs through an annual incentive scheme agreed with Ofgem. To avoid dampening cash-out prices when pre-contracted balancing services are used, the availability or option fees for these services are 'loaded' back into the prices based on a pre-defined methodology[43].

5.2.2 Potential issues

Balancing risk

The current arrangements present particular risks for intermittent generators due to the difficulty in accurately forecasting output for these plant. The Feed-in Tariff scheme proposed by the Government for sub-5 MW plant addresses this concern for small-scale generators by removing exposure to imbalance prices. Large-scale wind plant, however, are more likely to be exposed to unfavourable cash-out prices, a problem compounded by low within-day liquidity which may constrain the ability to balance positions as forecasts improve closer to real-time. As a result most renewable generation is either owned by vertically integrated players or sold to them under long term power purchase agreements with the buyer taking the imbalance risk. Hence, the market design may have implications for who builds and operates the large volumes of renewable plant required to meet the 2020 targets.

Generation forecast uncertainty

The current arrangements were not designed specifically with the challenges of managing high volumes of intermittent renewable plant in mind. There is of course significant uncertainty already in the current system that the SO must accommodate, due to forced outages from non-renewable plant (as the events of 27th May 2008 described in section 2.3 demonstrate), and uncertainty in demand. However, as the proportion of intermittent generation on the system increases, the scale of the problem becomes greater, and conventional power stations will need to be dispatched differently in order to maintain system balance. A key driver of this change will be the uncertainty associated with output from wind and other intermittent generation sources. Flexibility to adjust output must be therefore be retained on the system, which will probably require increasing levels of plant part-loaded, and thus potentially running for periods in which it would otherwise be loss-making, so as to be available to ramp up at short notice. Under current arrangements, companies will either enter into Ancillary Services contracts with Grid, internalise these costs where they "self-balance" (using their own generation to meet their own demand), or incorporate them into the price at which they sell standard energy products, or into the bid and offer prices they submit in the Balancing Mechanism. None of these provides a clear price signal for flexibility or a transparent means for other parties - for example, independent generators with a high proportion of renewables - to access flexibility to balance their positions.

[43] This is the Balancing Services Adjustment Data (BSAD) methodology which is developed by National Grid in consultation with Ofgem.

Changing diurnal profiles

In addition to the uncertainty of output, dispatch of conventional power stations will also change due to the pattern of wind generation. The residual profile left once renewable (and other inflexible plant) output has been netted off from demand will increasingly lose its consistent diurnal shape as the much more variable wind profile grows. The resulting dispatch patterns for thermal plant may thus change from today's typical profiles (such as 'two-shifting', where plant run during the day and turn off overnight). Optimising dispatch will therefore be harder, plant running regimes (possibly with more cycling, or longer periods at low output levels) may impose higher operational and maintenance costs and lower efficiencies, and hedging through typical peak and offpeak contract structures may be less effective.

Market power

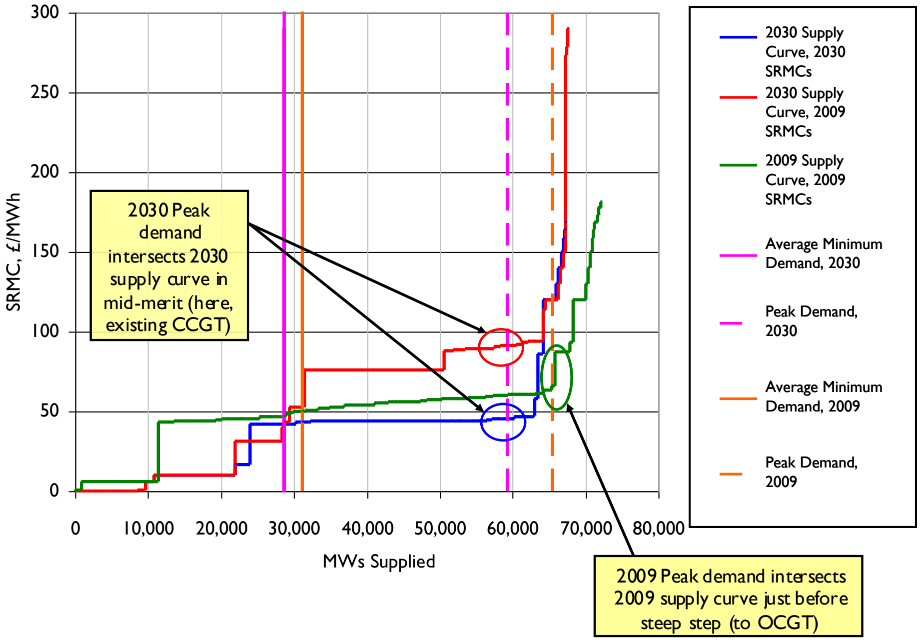
Even in a generation market with a wide distribution of ownership, there can be occasions when the opportunity for exploitation of temporary market power arises. This could occur as the result of a tight overall capacity margin, or when there is need for flexibility that can be provided by only a small number of plant. We discuss each of these below. We discuss locational market power due to transmission constraints in section 5.4.

We have seen that in the EFC scenario, there is only a small increase in the chance of tight or negative capacity margins compared to today, suggesting that opportunities to exploit short term market power may not increase significantly compared to today. We can also examine this in more detail by comparing supply curves as shown in Figure 34. Three supply curves[44] are shown: the current supply curve (green line), the modelled supply curve in 2030 if the output is valued at 2009 commodity prices (red line), and the modelled 2030 supply curve with output valued at assumed 2030 commodity prices (blue line). Where the intersection of the demand curve[45] with the supply curve is closer to the right, the opportunities to exploit short term market power increase, simply because only a few plant are left to meet any further demand increase. The steeper the supply curve, the greater the opportunities for exploitation of market power by portfolio generators, who can increase the revenues across the whole portfolio by withholding some capacity.

[44] Wind is shown on basis of annual average availability.

[45] For simplicity we are showing a vertical demand curve suggesting that short term demand is inelastic to price. In reality some demand side response would be available and this may increase over time as new technologies make demand side response from the mass market more achievable.

Figure 34 System supply curve, 2009 and 2030, EFC scenario



Due to the assumed decrease in peak demand assumed in the EFC scenario (the pink versus the red lines), there is in fact more 'room' at the right-hand side of the supply curve compared to 2009, and the intersection occurs at a point where the curve is relatively flat.

The supply curve representation is based purely on generation costs, and does not reveal the ability of different plant types to provide flexibility. Where there is a specific need for flexible plant, to meet system swings with high ramping rates, the supply curve "contracts" as plant with insufficient flexibility, although lower SRMCs, are unable to deliver the flexible generation: this compresses the supply curve, somewhat.

Under different sensitivities, particularly where the de-rated capacity margin is significantly lower, opportunities to exploit short term market power may increase more significantly. On the other hand, the development of a much more responsive demand side would be expected to reduce the opportunities for exploitation of market power on the generation side.

5.2.3 Potential developments

Evolution of traded markets

It is possible that the traded market could evolve in response to the changing requirements of players with substantial renewables positions. For example, more liquidity in half-hourly or hourly contracts may develop making it somewhat easier to balance different output profiles. (The recent developments with regard to day-ahead hourly auctions[46] may contribute to this, although the effectiveness may be limited since the difficulties of accurately forecasting wind output efficiently in advance of real time will remain.)

[46] In December 2008 the APX Group launched a day-ahead power auction and in October 2009 N2EX, a joint venture Nasdaq OMX and Nord Pool Spot, is set to launch a day-ahead auction and continuous trading of prompt contracts (electricity contracts with physical delivery).

This could be accompanied by a reduction in gate closure (say to 30 minutes) to allow later responses to changing wind output.

To handle uncertainty, new standard 'flexibility' products may emerge, effectively creating a more transparent and participatory market for reserve products typically managed today through confidential agreements between the SO and generators.

For flexibility products to work effectively (as for energy products), a credible set of price indices will need to evolve, to provide a sufficiently reliable settlement price for futures contracts. This in turn would allow better risk management tools for generators to manage their own positions.

This could be catalysed by changes to the way in which flexibility products are traded in the market. For example, rather than a Balancing Mechanism in which the SO is on one side of all transactions, an exchange for flexibility products in which the SO participated just like any other counterparty could drive liquidity.

Developments on the demand side may contribute to liquidity in this area. The roll-out of smart meters to all customers could be the start of the evolution of a platform for much more dynamic load management. Suppliers could centrally co-ordinate load-shifting or small-scale distributed generation output, aggregating their portfolio of customers to support a range of energy or flexibility products. In the longer term, a growing fleet of electric vehicles may greatly expand the scale with which this could operate.

Deployment of smart grids may change the nature of system operation, and it is possible to envisage more 'devolved' system operation with the distribution network operators (DNOs) playing a wider role in local balancing.

Changes in the way the utilities operate could also spur developments here. Since NETA, the major players have aimed to create vertically integrated businesses that are relatively balanced across generation and supply. As the proportions of wind in portfolios increase, however, 'self-balancing' may become increasingly difficult, and the potential inefficiencies of 'internal reserve provision' could increase. In particular, the variability of wind across the system will typically be less (proportionately) than the variability in any one portfolio. Players may therefore choose increasingly to balance through the traded market, driving greater liquidity. Structural moves, for example, decisions by one or more of the big players to divest their supply businesses, could have a similar, albeit potentially swifter and more dramatic, impact on liquidity.

Finally, the regulator may take explicit steps to try to improve liquidity in the market[47].

Centralised dispatch

Despite the potential benefits of liquid markets, recent trends have indicated increasing concerns with regard to liquidity, and if anything a greater propensity for self-dispatch by generators. In light of the increasing complexity of balancing the system and changing profiles of dispatch, a more centralised approach could be considered, rather than leaving dispatch and balancing decisions largely at the level of individual firms.

Market designs with centralised dispatch can help in overcoming the risk associated with the self-dispatch/bilateral trading approach that low within-day liquidity or collective risk aversion leads to sub-optimal dispatch, scheduling of reserve and response to potential generation outages. Transparency in system operation may increase, and there would be greater price transparency. This should facilitate the regulator's market monitoring role, and provide reliable reference prices against which contracts can be settled thus potentially stimulating liquidity.

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[47] Ofgem published a Discussion Paper on Liquidity in the GB Wholesale Electricity Market in June 2009, and is currently considering options to improve liquidity.

On the other hand, centralised scheduling and dispatch rules can be complex, and open to challenge. There is a risk that innovation in system operation is stifled, particularly with regard to small-scale generation and demand side participation. Further, market rules will determine participants' dispatch decisions rather than market signals and this creates risks of inefficiencies where these are poorly designed.

Centralised dispatch does not have to cover all plant. It would be possible to centralise the management of wind (and other intermittent renewable). For example, the SO could take a greater role in within-day balancing of wind generation and there may be advantages in it doing so since there may be efficiencies in forecasting wind output at an aggregate level, and allowing it to take more co-ordinated decisions with respect to scheduling of reserve and managing potential transmission constraints. (It may become increasingly difficult to do this using the Balancing Mechanism, and yet a move to increase bilateral balancing contracts could reduce transparency.)

Under centralised dispatch for intermittent renewables, wind and marine generators would have their positions 'deemed' at some point prior to delivery and would receive the market clearing price for its output less a balancing fee. From this point on, the SO would be responsible for balancing the intermittent renewable portfolio on the system and would be exposed to the costs involved (within an overall incentives framework).

The potential benefit of this approach for renewables generators, particularly smaller players, is that they would avoid the risks of balancing within the current cash-out regime.

5.3 Incentivising capacity and flexibility

5.3.1 Current arrangements

BETTA is an "energy only" market. Companies receive revenues by selling the electricity they generate, and are not remunerated by any central mechanism for making capacity available. This is in contrast to the England and Wales Pool (replaced by NETA in 2001), which included a capacity payment mechanism.

Generators (and large consumers) do have the opportunity to secure additional income streams through Balancing Services contracts with the SO. National Grid procures a number of different services including different forms of reserve, frequency response, black start, and services to reduce transmission constraints. Some of these services are procured through open tenders.

In April 2009, National Grid launched a long term reserve contract extending up to ten years. It stated that new and refurbished assets would be encouraged to participate in the tender process. Contract award would be possible prior to the asset investment taking place, with long term service providers having the option to link their availability and/or utilisation payments to an agreed indexation methodology.

To an extent the central procurement of reserve by the SO can be considered to be an alternative to incentivising capacity to be made available via a centralised capacity payment mechanism.

5.3.2 Potential issues

The modelling suggests that, if prices are able to rise to reflect scarcity and investors behave rationally, sufficient capacity will be built and maintained on the system to deliver a reasonable level of security of supply. As the de-rated capacity margin tightens, prices will rise, stimulating new investment and deferring retirements. Similarly, if there is real value in the market for flexibility, and investors are able to see transparently how that value can be captured, this will be incorporated in investment decisions.

However, where investors are strongly risk averse, or weight investment decisions based heavily on current, rather than potential future, market conditions (and hence do not place value on potential future opportunities), our modelling indicates that capacity margins could fall to levels at which the risk of involuntary demand reduction becomes more material.

There is also a heightened risk if the value of scarcity is not correctly reflected in market prices (as demonstrated in our Peak prices dampened sensitivity), possibly because the actions taken by the SO dampen cash-out prices as seemed to be the case in the example of 27 May 2008. Ultimately this may lead to the SO needing to contract for more reserve which in turn could compound the problem by furthering dampening price signals at peak.

5.3.3 Potential developments

Transparency and information

The value of flexibility in the market is currently opaque, due in part to the complex and often confidential nature of balancing services contracts[48]. Whilst Balancing Mechanism data is available it is a complex exercise to interpret the sequences of actions by Grid in order to evaluate the value of flexibility. It is also difficult to gauge flexibility needs on the system even for a few years out[49], and made more complex by the divergent geographical need for flexibility across the system.

The potential developments around traded markets discussed above would also help to address this issue and provide clearer signals for investment decisions. If a forward market for flexibility products developed, this would provide much clearer price signals. Other approaches could involve obligations on the SO to develop a more transparent and standardised procurement process for all reserve services[50], again with the intention of providing price signals to investors.

Improvements to the cash-out arrangements

The issue surrounding the dampening of price signals caused by the SO's actions is well noted. For example, Ofgem in its Impact Assessment of Balancing and Settlement Code (BSC) modification P217, suggested that the way that reserve costs are allocated could be distorting price signals. The phenomenon has also been noted in other markets. In the US it is frequently referred to as the 'missing money' problem.

Revisions to the cash-out arrangements to reflect more accurately the value of energy in each period may encourage suppliers to take further actions to cover their peak positions and hence provide stronger signals for the provision of peaking capacity,

Capacity payments

The principal objective of capacity payment mechanisms is to provide additional revenues to cover the fixed (and investment) costs of peaking plant which are occasionally required to meet high demand periods or

[48] National Grid procures balancing services through both competitive tenders and through bilateral negotiation with BMUs.

[49] NGC articulates some of the future challenges faced in its June 2009 consultation document: Operating the Electricity Transmission Networks in 2020.

[50] National Grid procures Short Term Operating Reserve (STOR) through a competitive tender process which is conducted three times per year. Other reserve services including Demand Management, Fast Start and BM Start Up are procured through bilateral commercial agreements.

replace plant outages. They may also reduce short term price volatility, thus stabilising income streams for all generators and potentially lowering the risk of investment. Several jurisdictions (notably in the US) feature explicit mechanisms to reward the provision of generation capacity.

Capacity payment mechanisms are generally accompanied by price caps and/or bidding restrictions in the energy market since it is assumed that generators should no longer need to increase prices above their short run marginal costs in order to cover their fixed costs and earn a reasonable return on investment. Thus the regulator no longer has the difficult role of distinguishing genuine scarcity pricing from exploitation of short term market power. Having said that, historical and international experience has demonstrated that poorly designed capacity payment mechanisms can themselves be open to manipulation. A further challenge is that the capacity payment mechanism requires the Government (or regulator) to anticipate the correct quantity of capacity, requiring it to forecast accurately future demand, and anticipate current and future customers' appetite for reducing their energy bills by changing their usage patterns. By dampening short term price volatility, capacity payments could stifle innovation on the demand side, just as new technologies to enable it, such as smart meters, are being rolled out. Although capacity payments arguably reduce market risk for investors they may lead to a higher perception of regulatory risk, since changes to the mechanism are quite likely in response to experience of how it is operating.

The modelling results suggest that investments in baseload plant and renewables are less sensitive to expectations around scarcity rents since the bulk of margins derive from capturing infra-marginal rents[51], and subsidies in the case of renewables. If the introduction of capacity payments did not lead to a fall in energy prices (or accompanied by explicit price caps) there is a risk of windfall profits for baseload generators. It may be possible to introduce capacity payments only for certain types of peaking plant, but again this would need to be carefully defined.

Tendering for flexible generation

A possible more targeted alternative to capacity payments would be a process of tendering for back-up or flexible generation. This could be seen as an extension of Grid's existing long term reserve contracting process, and could be tied to a more specific security of supply obligation. For example, the SO could estimate the volume of back-up generation required based upon anticipated levels of intermittency, and then tender for this volume from a wide range of resources including new build generation, demand side response, mothballed plant and interconnectors, as well as existing plant. As with National Grid's current reserve auctions, tenders could be held for multiple products depending on the types of flexibility required and could be for capacity only (with a fixed or indexed exercise price) or for a bundled product. Similar set-ups currently exist in the Nord Pool markets of Norway, Sweden and Finland, with the respective system operators using additional instruments to help ensure generation adequacy in these "energy only" market. Such an approach is advantageous in that it can be tailored to promote investment in flexibility, including the demand side.

This would face a similar difficultly to the capacity mechanism in that it will be difficult to define the required volume. Additionally, it may displace investment that would otherwise have occurred. This could be mitigated by very clear rules as to how the plant would be used by the SO, and how balancing prices would be set on those occasions, to avoid dampening the associated price signals.

[51] The carbon price in the EFC scenario is a main driver of the infra-marginal rents for baseload capacity.

5.4 Locational issues

5.4.1 Current arrangements

The current market arrangements do not provide short term locational signals. BETTA operates with the concept of a single balancing point, and a single wholesale price for the market as a whole. Theoretically, participants therefore trade and schedule generation in the first instance as if there were no transmission constraints. It is then the responsibility of the SO to resolve any transmission constraints that do emerge, by buying and selling on each side of the constraint to rebalance flows sufficiently. It can do this using bids and offers in the Balancing Mechanism, along with the use of bilateral contracts with generators at locations where constraints are frequent.

The costs associated with handling transmission constraints are not currently targeted, but are spread across all system users through Balancing System Use of System (BSUoS) charges. The way in which network use of system charges are set is intended to provide locational signals for investment in generation capacity, with higher charges in areas where new generation would increase constraints, and lower (or negative) charges where new generation would help reduce constraints.

5.4.2 Potential issues

Efficiency of resolving constraints

Ignoring transmission constraints in the formation of market prices and generation dispatch schedules may not lead to the most efficient outcomes. The absence of short term locational signals in a uniform pricing market such as GB means that the short term costs of transmission congestion and losses are not directly targeted to the system users that contribute to these costs. Without incentives on generators behind export constraints to reduce output, overall constraint volumes may increase. In a system which is usually relatively unconstrained, as was the case with NETA in England and Wales[52], this may be of little materiality. The generation schedule arising from trading in the national market will be a reasonable proxy to a transmission feasible schedule. However, where constraints become frequent, the resulting additional costs can become more significant. There are frequent constraints between Scotland and England, and within Scotland, and the expansion of NETA to BETTA in 2005 led to these network capacity restrictions being absorbed within a wider GB market. The occurrence of constraints could increase further under proposals for grid access reform that the Government is currently consulting on. Under a principle called 'Connect and Manage' new renewables could be connected in advance of network reinforcements. This is likely to lead to temporary increases in the occurrence of constraints.

Market power

As discussed above, the existence of transmission constraints often creates situations of temporary market power, as in many cases only one or a few generators may be able to change output to resolve the constraint.

[52] Transmission constraints had been a greater issue during the early 1990s under the Pool prior to a programme of network reinforcements and financial incentives on National Grid to reduce constraint costs.

5.4.3 Potential developments

Nodal pricing

A number of markets (including those in the North Eastern US, and in New Zealand) use a fundamentally different approach to dispatch, by which the physical structure of the grid is built into an optimisation process that solves for dispatch and transmission flows simultaneously. This process calculates separate prices at each of many (potentially thousands) of nodes across the system. Participants can hedge the associated basis exposure through financial contracts based around a smaller number of hubs (to concentrate liquidity).

This may provide a more efficient dispatch solution, and reduce the cost of managing congestion, and reduces complexities associated with allocating and trading capacity access rights. It also provides greater transparency around generator behaviour in constrained locations, and may facilitate the monitoring of potential exploitation of locational market power.

However, such a regime would be very complex to design, implement and administer, and there would be a risk that insufficient liquidity in the trading of financial transmission rights might leave participants exposed to locational basis risks that were difficult to manage. It would also be difficult and controversial to determine how to compensate existing players who would effectively lose existing firm transmission access rights.

Zonal pricing

A zonal pricing arrangement would have a much smaller number of pricing points than nodal pricing (potentially as few as two), and hence may provide better liquidity and reduced complexity where transmission constraints are reasonably well defined between regions. It would also be compatible with a bilateral market, and consistent with the market coupling method of allocating transmission capacity which is currently being operated between France, Belgium and the Netherlands.

Whilst less flexible than nodal pricing, zonal pricing could provide a more practical approach to addressing specific constraint problems, particularly if a bilateral market was retained, and one consistent with neighbouring markets on the continent.

The targeting of constraints costs under some of the proposals for Connect and Manage may effectively create a zonal market in GB since the value of electricity generated in different regions will vary depending on the constraint charges.

5.5 Summary

As the level of intermittent generation on the system increases, so will the value of providing flexibility. This value is currently largely embedded within the price of traded energy products, or within companies' own self-balancing provisions. Ensuring decisions are efficient with respect to these costs may require developments in the traded markets (for example, standard flexibility products), or more centralisation of some elements of balancing, perhaps specifically related to intermittent plant. Increasing the transparency and longevity of contracts for the provision of flexibility services will facilitate investment as these revenues become 'bankable' for generators and financing can be secured against the income..

Under the current arrangements, investors make decisions, and take associated risks, based on market price signals, both from the wholesale traded market and the Balancing Mechanism. There is no evidence historically (either in GB or in other "energy only" markets elsewhere in Europe) that this should not provide an adequate level of security of supply under normal circumstances. However, the demands of meeting very challenging environmental targets in a short timeframe, and the associated need for significant intervention, may present regulatory uncertainties that are harder for the market to handle efficiently, particularly given the sensitivity to levels of prices in a handful of peak hours. Measures to address this could range from mechanisms to improve transparency and price signals, through to remunerating capacity more directly (potentially through an enhanced role for the System Operator). Approaches for the latter would need very careful design, place a difficult onus on policy makers to predict requirements, and should be targeted carefully at specific capacity types.

There are existing issues with the handling of transmission constraints, and the increase of intermittent capacity at network extremities is likely to exacerbate this. Nodal pricing regimes, deployed elsewhere (although untested with significant intermittent renewables penetration), provide a theoretical approach to tackling this, though at a cost of complexity. Zonal pricing is simpler and would be consistent with developments on the continent.

A Environmentally Favourable Conditions scenario

A.1 Introduction

This appendix describes in detail both the modelling assumptions and key outputs of the EFC scenario. The EFC scenario is one in which conditions are favourable to drive decarbonisation of the power sector. It includes a high level of renewables build, increasing effectiveness of energy efficiency measures and high carbon prices which encourage investment in non-fossil fuel plant. In the results section we illustrate the potential impact of rapid decarbonisation in terms of price levels, investment signals, security of supply, and levels of spilled electricity.

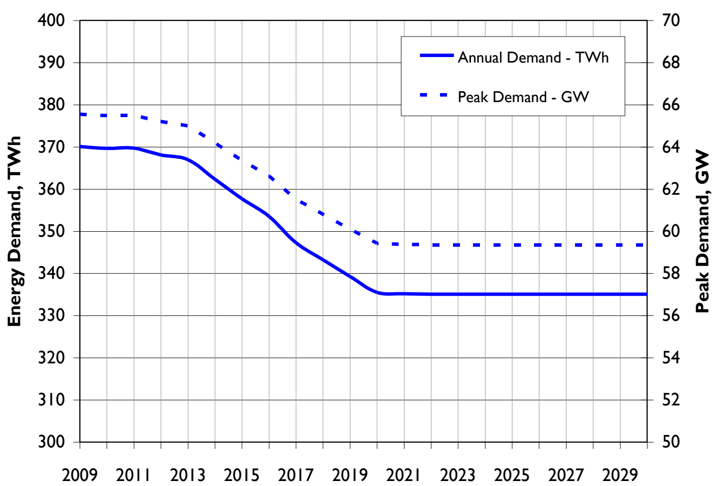
A.2 Assumptions

A.2.1 Demand

Figure 35 shows the annual electricity demand and annual peak demand assumptions for the EFC scenario. Annual electricity demand in 2009 is assumed to be 370 TWh while the peak is 65 GW. The CCC provided the growth rates for energy and peak demand assumptions; these are consistent with widespread adoption of energy efficiency measures through to 2020 which more than offset the growth in consumption. By 2020, energy demand has fallen by 35 TWh (the equivalent of approximately 5 GW of baseload capacity). Beyond 2020, energy demand remains constant at 335 TWh through to 2030: the energy efficiency improvements keep pace with the growth in consumption.

In the EFC scenario we have not assumed widespread adoption of electric vehicles or significant electrification of the heating sector. These effects are separately tested in sensitivities 3-EP and 4-EO. We have assumed that the daily shape of demand remains the same, and thus the change in peak demand tracks the change in overall energy demand. In 2020, peak demand is assumed to be 59 GW, remaining constant through to 2030.

Figure 35 Electricity energy and demand growth



The demand definition used in the modelling is total national demand at station gate. This includes demand served by onsite and embedded generation, and electricity 'lost' through transmission and distribution losses. The parasitic load of power stations (i.e. own consumption), which amounts to approximately 20 TWh per year, is excluded from this demand metric[53].

We have assumed approximately 1 GW of voluntary demand side response in the EFC scenario as follows[54]:

- 760 MW reduction @ 100 £/MWh
- 170 MW reduction @ 200 £/MWh
- 60 MW reduction @ 500 £/MWh

The size of the tranches scales up/down in relation to the increase/decrease in annual energy, while the price of the tranches shifts up and down in relation to the annual oil price. For this scenario we have not attempted to estimate the potential increase in demand side response that may be enabled by new technologies such as smart metering and smart appliances.

A.2.2 Commodity Prices

The EFC scenario is based on DECC's commodity price projections (as at February 2009). Commodity prices are the main determinant of the short-run marginal costs (SRMCs) of fossil fuel electricity generation, and thus a primary driver of wholesale electricity prices.

The exchange rate assumptions used in the modelling are shown in Table 10. These are assumed to be constant over time. The same rates are applied in all years of the EFC scenario.

Table 10 Exchange rate assumptions

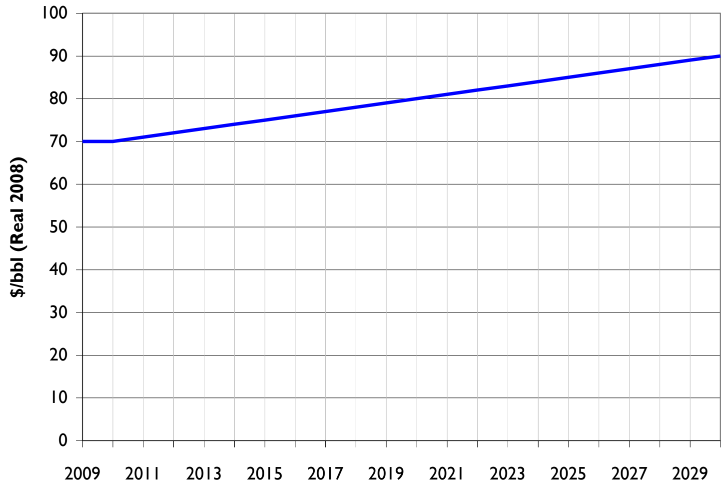
Exchange rates	
€:£	1.43
$:£	1.60

Brent crude oil prices for the EFC scenario are shown in Figure 36. In 2009, the oil price is 70 $/bbl and this trends gradually upwards to 90 $/bbl (in real terms) by 2030. The oil product prices are indexed to Brent: we apply ratios of 1.3 and 0.8 to derive the Distillate and Heavy Fuel Oil (HFO) price respectively.

[53] Note that this demand definition is different to that produced by National Grid, which nets off the demand from small-scale embedded generation.

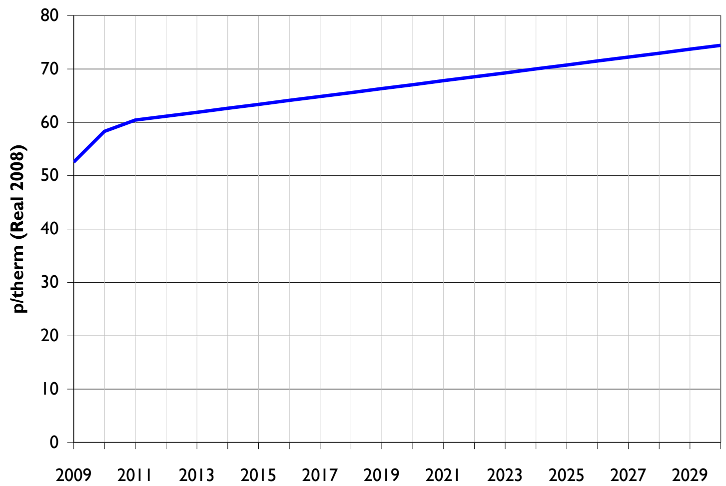
[54] Source: Global Insight. May 2005. Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices.

Figure 36 Brent crude price assumptions[55]



The gas prices in the EFC scenario are shown in Figure 37. Beginning from a base of 52.5 p/therm in 2009, the price steps up to 58.3 p/therm in 2010, beyond which it gradually trends to 74.4 p/therm by 2030 (all in real terms). These are annual average prices: we apply seasonality factors of +/- 10 percent to derive summer and winter gas prices.

Figure 37 Gas price assumptions[56]

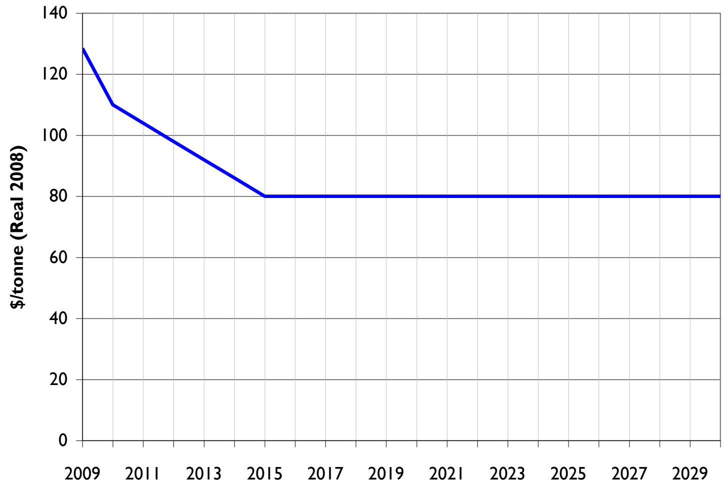


The international coal prices (Amsterdam-Rotterdam-Antwerp (ARA)) basis in the EFC scenario are shown in Figure 38. The price trends down from a high of 128.50 $/tonne in 2009 to 80 $/tonne (in real terms) in 2015, after which it remains constant in real terms through to 2030.

[55] Source: DECC (2009) Communication on DECC Fossil Fuel Price Assumptions

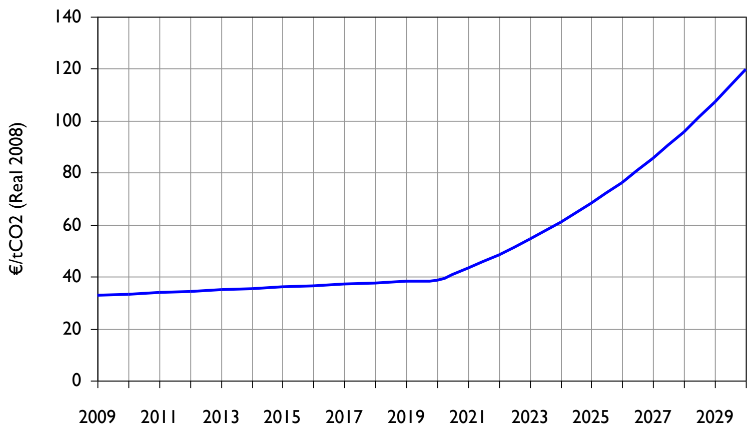
[56] Source: DECC (2009) Communication on DECC Fossil Fuel Price Assumptions

Figure 38 Coal price assumptions[57]



Finally, the EUA prices in the EFC scenario are shown in Figure 39. Carbon prices are 32.8 €/tonne in 2009, trending upward to 38.7 €/tonne in 2020. The CCC's EUA price projections assume that a global agreement is reached on climate change and the EU's reduction target for 2020 increases from the current 20 percent to 30 percent. After 2020 the EUA price rises sharply to 2030, when it reaches approximately 120 €/tonne. This smoothly increasing cost of EUAs suggests that expectations of carbon supply/demand balance progressively tighten over time. In reality the carbon price is likely to evolve through a series of jumps (and falls) as new information emerges on global agreements, country allocation plans, and historic emissions.

Figure 39 EUA price assumptions[58]



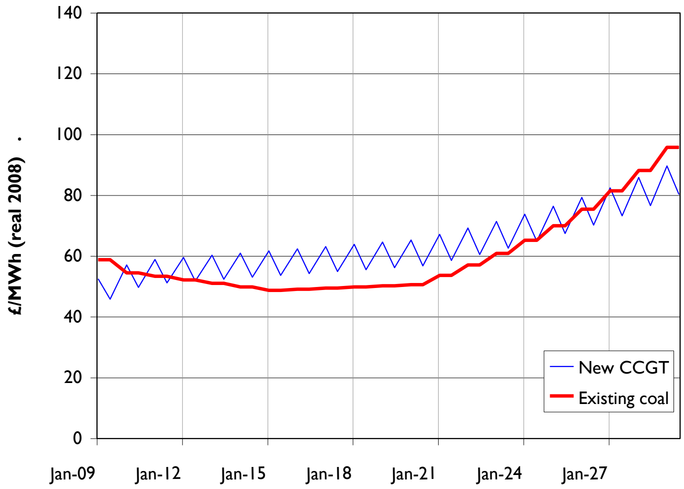
[57] Source: DECC (2009) Communication on DECC Fossil Fuel Price Assumptions

[58] Source: CCC

Short Run Marginal Costs

Figure 40 below shows the short run marginal cost (SRMC) for a typical existing coal and a new CCGT plant in the EFC scenario, based on the fuel prices, carbon prices and exchange rates described above. The SRMC of the CCGT reflects the winter/summer seasonality of the gas prices.

Figure 40 SRMCs for existing coal plant and new CCGT



The assumptions for the two plant types are shown in Table 11.

Table 11 Plant assumptions

Plant	Efficiency	Non-fuel variable costs	Transportation charges
New CCGT	53% (HHV)	0.40 £/MWh	1 p/th
Existing coal	36% (LHV)	2.00 £/MWh	0.4 £/GJ

The fuel and carbon prices in the EFC scenario favour gas on a short run marginal cost basis in the very near term, but after 2011 coal-fired generation is lower cost than gas-fired generation. This reverses after 2023 due to the sharply rising EUA prices leading to gas becoming less expensive than coal. In the years of the scenario where coal and gas prices are similar on an annual basis, the seasonality of gas prices favours gas plant over coal. The CCGTs are less expensive when demand is lower during the summer and hence they achieve higher load factors than coal plant during the summer. When CCGTs are more expensive than coal during the winter (at least during the earlier years of the scenarios) electricity demand is also higher and hence they still run at reasonably high load factors.

A.2.3 Plant costs

The new entrant costs assumptions for the EFC scenario are set out in Table 12. The capital cost represents the all-in cost for a greenfield development, excluding interest paid during construction. The capital costs fall in real terms through to 2020. Note that for renewable plant there is a supply curve within the model representing the different costs of developing projects in different sites: the values shown in Table 12 represent the least-cost tranche of capacity and hence capital cost for renewable plant in any particular year may differ from that shown in Table 12 and is dependent on the rate of deployment of a particular technology.

A steady improvement in the efficiency of thermal plant is assumed. We model the improvement linearly. In reality there will likely be a series of step changes as new technology becomes available.

The annuitised capital costs are shown in £/kW based on the economic lifetimes shown. These are based on the project hurdle rates for a typical utility. Hurdle rates for independent developers are assumed to be higher.

Finally, assumptions are made on the planning time and build time for each technology. In the investment decision process, if an investor decides to develop a plant, it will enter a planning phase. The investor can withdraw from the project investment during the planning phase if the expectations of future profits become less favourable. However, once the project enters into the construction phase, the capital is deemed to be sunk and the project will be commissioned, irrespective of how conditions may evolve over the build period.

Table 12 New entrant cost assumptions[59]

Plant	Capital cost - £/kW (real 2008)		Thermal efficiency[60]		Economic life (yrs)	Annuitised capital cost (£/kW)	Planning time (yrs)	Build time (yrs)
	2009	2020	2009	2020				
CCGT	650	585	53%	55%	20	80	2	3
Coal (ASC)	1375	1238	45%	46%	25	167	3	4
Coal (IGCC)	1850	1711	46%	50%	25	226	3	4
Coal (CCS)	2397	2157	33%	38%	25	351	3	4
Nuclear	2000	1800	36%	36%	30	250	3	6
Onshore wind (High yield)	1250	1026	-	-	20	133	4	1
Onshore wind (Medium yield)	1250	1026	-	-	20	135	4	1
Onshore wind (Low yield)	1250	1026	-	-	20	142	4	1
Offshore wind (High yield)	2750	1925	-	-	20	341	4	2
Offshore wind (Low yield)	2750	1748	-	-	20	313	4	2
Biomass regular	2500	2124	28%	28%	20	280	2	2
Biomass energy crop	2500	2124	28%	28%	20	286	2	2
Biomass CHP	3250	2761	16%	16%	20	379	2	2
Wave	4250	3665	-	-	20	604	4	2
Tidal Stream	4250	3664	-	-	20	586	4	2
Tidal Range	3800	3078	-	-	30	467	4	4
Biowaste	3615	3071	-	-	20	411	2	2
Biogas	6606	5826	-	-	20	801	2	2
OCGT	350	315	37%	40%	20	52	1	2

The non-fuel variable operating costs and annual fixed costs for each technology are set out in Table 13. The table also includes the annual availability: this is the expected maximum annual load factor that each plant can achieve after unplanned outages and maintenance.

[59] Source: DECC

[60] Gas plant is quoted on a High Heating Value (HHV) basis.

Table 13 Plant operating characteristics[61]

Plant	Non-fuel variable costs (£/MWh)[62]	Annual fixed costs (£/kW)	Annual availability (%)
CCGT	2.00	15	83%
Coal (ASC)	1.60	24	83%
Coal (IGCC)	2.00	33	83%
Coal (ASC + CCS)	2.60	39	83%
Nuclear	5.00	40	87%
Onshore wind (High yield)	0.00	40	29%
Onshore wind (Medium yield)	0.00	40	27%
Onshore wind (Low yield)	0.00	40	21%
Offshore wind (High yield)	0.00	68	41%
Offshore wind (Low yield)	0.00	68	35%
Biomass regular	1.10	62	80%
Biomass energy crop	1.10	62	80%
Biomass CHP	1.10	83	80%
Wave	0.00	106	30%
Tidal Stream	0.00	85	35%
Tidal Range	0.00	54	23%
Biowaste	0.00	97	73%
Biogas	0.00	90	61%
OCGT	2.00	13	90%

Figure 41 shows the evolution of the levelised long run marginal costs[63] (LRMC) for five different plant types. The calculation of levelised LRMC requires an assumption on the load factors of different plant. If the plant runs at lower load factor there are less running hours over which to recover fixed operating costs and capital costs, and hence the levelised LRMC cost goes up. Nuclear and coal fitted with CCS are

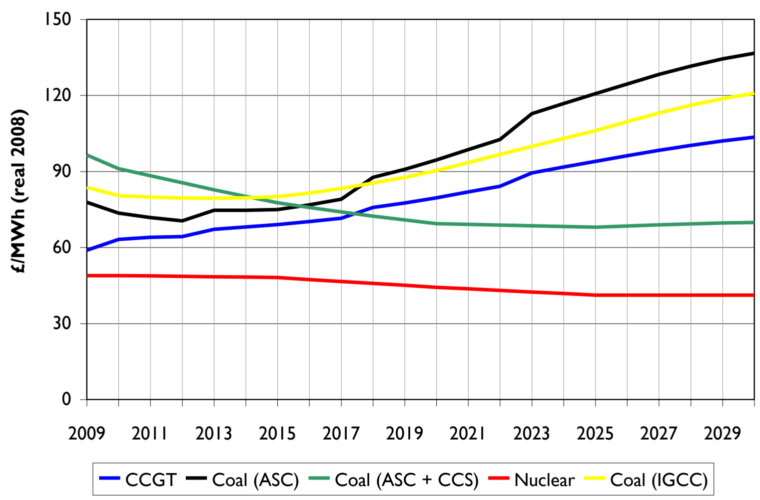
[61] Source: DECC

[62] Excludes BSUoS

[63] The levelised LRMC includes the SRMC, and the annual fixed operating costs and annuitised capital costs divided by the expected running hours.

assumed to run at baseload i.e. at their maximum annual availability. However, we assume that investments in CCGTs and unabated coal[64], which have higher short run marginal costs, must factor in a reducing expectation of load factor over time. The investment decision within the model for CCGT and unabated coal is therefore based on an expected load factor which falls from baseload in the near term to mid-merit (60 percent load factor) by 2023. The growing divergence in levelised costs between unabated Coal and CCGT through the scenario reflects the assumption on expected lower load factor running for conventional plant: the lower capital intensity of CCGT plant clearly has a relative cost advantage over coal plant in cases where the plant are not running baseload.

Figure 41 Long run marginal costs



A.2.4 Interconnection

Currently GB is interconnected to France (2 GW) and Northern Ireland (500 MW). Imports from France have historically averaged 11 TWh per annum, although this has fallen as low as 5 TWh in 2003, when the French nuclear plant encountered significant outage problems due to abnormally high temperatures during the summer. There is a 120 MW import contract through the Moyle interconnector from Northern Ireland (NI), although power through this interconnector typically flows in the opposite direction i.e. from Scotland to NI.

In the EFC scenario further interconnection is assumed to be developed:

- The 1.3 GW BritNed interconnection between GB and the Netherlands is commissioned in 2011; *and*
- The 500 MW interconnector between Wales and Republic of Ireland is commissioned in 2012;

It is possible that there will be further interconnection before 2030, possibly in response to the need to balance intermittent generation across North West Europe, but we have not assumed this in the EFC scenario.

[64] To the extent that investment in unabated coal is permitted.

The investment decision model uses simple assumptions on the flows on interconnectors when the system is short or long, rather than a fully priced based approach. Table 14 sets out the assumptions for each interconnector.

Table 14 Assumptions on interconnector flows

	System short	System long
Moyle/ROI	○ Full export	○ Net zero
BritNed	○ Net zero	○ Full export
French	○ Full import	○ Full export

A.2.5 Known new build and retirements

In the longer timeframe the model makes its own decision on plant build and retirements based on the economics of the scenario. However, we also include assumptions on known new build and retirements over the medium term.

Table 15 sets out the plant that are either under construction or at advanced stages of planning. The expected commissioning year and the capacity for the thermal plant are also shown. There is an assumption made that the 300 MW Carbon Capture and Storage competition plant (part funded through Government subsidy) is commissioned in 2014.

Table 15 Committed new build (thermal plant)

Plant	Year of commissioning	Capacity (MW)
Langage (Centrica)	2009	1000
Marchwood (SSE/ESBI)	2010	800
Immingham (Conoco)	2010	450
Severn Power (DONG)	2010	840
Grain (EON)	2012	1275
West Burton (EdF)	2012	1275
Staythorpe (RWE)	2010/2012	1600
CCS competition plant	2014	300
	Total	***7540***

Table 16 shows the assumptions of known new renewable capacity over the next two years.

Table 16 Committed new build (renewable plant)

Plant	2009	2010
Onshore wind	645	307
Offshore wind	464	474
Total	***1109***	***781***

Committed retirements

We also make assumptions with respect to known plant retirements: specifically for nuclear plant and those coal and oil plant opted-out of the Large Combustion Plant Directive (LCPD) or affected by the Industrial Emissions Directive (IED). The assumed retirement dates for the existing nuclear plant are shown in Table 17. We have assumed five year lifetime extensions for Hartlepool, Heysham 1, Heysham 2 and Torness. Approximately 7 GW of nuclear plant is due to retire before 2020.

Table 17 Nuclear capacity decommissioning schedule

Plant	Year of closure	Capacity (MW)
Dungeness B	2018	1110
Hartlepool	2019	1210
Heysham 1	2019	1150
Heysham 2	2028	1250
Hinkley Point	2016	1220
Torness	2028	1250
Hunterston	2016	1190
Sizewell B	2045	1190
Oldbury	2009	434
Wylfa	2012	980

The LCPD and its proposed successor, the IED, aim to reduce emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_X) from the European power sector. The compliance deadline for existing plant under the LCPD was 1st January 2008. Existing coal and oil plant can opt into the LCPD and achieve compliance through to 2015 by one or all of the approaches below:

- Burning low sulphur fuel;
- Reducing plant load factor;

- Installation of Flue Gas Desulphurisation equipment (FGD): this is the most common approach to reducing SO_2 emissions, although this does require significant capital investment.

Opted-in existing plant in the UK must either comply with instantaneous emission limit values (ELVs – limits per MWh of output), or participate in the National Emission Reduction Plan (NERP[65]). All plant that have opted-out of the LCPD must close before the end of 2015, and have their running hours limited to 20,000 between the start of 2008 and the end of 2015. How these running hours are used up depends on the economics of the scenario. Table 18 shows when the opted-out plant close under the EFC scenario.

Table 18 LCPD opt-out plant closure dates

Plant	Year of closure	Capacity (MW)
Ferrybridge (2 of 4 units)	2012	980
Ironbridge	2012	964
Tilbury	2013	1121
Kingsnorth	2013	1966
Littlebrook	2014	1245
Didcot A	2014	2100
Fawley	2015	1036
Grain	2015	1355
Cockenzie	2015	1152
	Total	***11.9 GW***

The Industrial Emissions (Integrated Pollution Prevention and Control) Directive, known as the IED, has been drafted with the objective of consolidating a number of existing directives, including the LCPD, to cover all industrial emissions, not only gaseous emissions to the atmosphere. The IED requires a further tightening in emissions standards beyond the end of the current LCPD compliance period in 2015. Therefore coal plant that have opted-in to the LCPD (and for the most part have fitted FGD) face another investment decision by 2015; in order to be able to continue operating at high load factors the existing coal plant must consider fitting abatement technologies such as Selective Catalytic Reduction (SCR) to reduce NO_X emissions. The tighter emissions limits under the IED will also apply to gas-fired plant as well as solid and liquid fuel plant.

The terms of the IED were negotiated after the analysis for this study was completed. Therefore it was necessary to make assumptions on how it would be implemented. We assumed that those coal and older gas plant that did not meet the required emissions standards[66] would have the option of opting in to a NERP[67] rather than fitting selective catalytic reduction (SCR) NO_X reduction equipment. The NERP is

[65] The NERP concept is an annual 'bubble' limit on emissions. Under the LCPD the most binding constraints are for SOx emissions. Under the IED, the NOx constraints are likely to bind also.

[66] The applicable emissions standards for NOx are 200 mg/Nm3 for coal and 50 mg/Nm3 for CCGTs.

[67] The NERP limit post-2015 was derived from the modelled load factor for each plant over the period 2008-2010.

similar in concept to the Transitional National Plan (TNP) which was finally agreed during the IED negotiations. However, we assumed that plant could operate indefinitely under a NERP, whereas under the TNP after 2020 plant can only operate under a derogation of 1500 hours per year[68]. We assumed no equivalent of the Limited Lifetime Opt-out (LLO)[69] derogation which was also a feature of the IED agreement. The decisions individual generators make are dependent on the economics of the scenario. Typically, plant operating under a NERP close before those plant that have chosen to fit SCR. We discuss plant retirements further below.

A.2.6 Renewables policy and infrastructure

One of the core assumptions in the EFC scenario, is that that renewable generation reaches 32 percent of demand by 2020, or 105 TWh. Thereafter generation from renewable sources continues to grow after 2020 but at a slower pace and reaches close to 36 percent by 2030.

In order to stimulate these levels of renewables deployment we assumed that the Renewables Obligation is extended by ten years to 2037/38 and RO bands (and feed-in tariffs for sub-5 MW plant) are set to make investment in renewables attractive. We assume that the size of the Renewables Obligation, once the annual targets expire in 2015/16, increases to maintain at least an 8 percent headroom. We also assume that reforms in transmission access and planning, and expansion of the supply chain, increases the rate at which renewables can be deployed.

Although banding is set to deliver the target 32 percent by 2020, there are annual build constraints applied for each technology. These are shown in Table 19.

[68] In the end all plant operating under the NERP in the EFC scenario close by 2023.

[69] Under the LLO a plant has its operating hours limited to 20,000 between the beginning of 2016 and end of 2023, i.e. equivalent to the LCPD opt-out arrangements.

Table 19 Renewables build rate constraints (MW per annum)[70]

Plant type	2009	2010	2011	2012	2013	2014	2015	2020	2025
Onshore wind	600	700	800	900	1000	1100	1200	1500	1500
Offshore wind	660	870	1090	1310	1400	1400	1600	1800	2000
Biomass regular	120	120	120	120	120	120	120	120	120
Biomass energy crop	25	25	25	25	25	25	25	25	25
Biomass CHP	25	25	25	25	25	25	25	25	25
Wave	0	25	35	45	55	65	75	150	240
Tidal Stream	0	60	120	180	240	240	240	240	240
Tidal Range	0	0	0	35	75	120	200	200	200
Biowaste	60	60	60	60	60	60	60	60	60
Biogas	60	60	60	60	60	60	60	60	60

The profile of renewable generation across the year will impact significantly on pricing, security of supply and emissions. In particular generation from intermittent sources will affect the operation of the conventional plant on the system. Assumptions on the level of wind generation are set out below. The following assumptions are made for the annual availability of wind plant.

Table 20 Annual availability of wind plant

Plant	Annual Average availability
Onshore wind (High yield)	29%
Onshore wind (Medium yield)	27%
Onshore wind (Low yield)	21%
Offshore wind (High yield)	41%
Offshore wind (yield)	35%

A.2.7 Carbon policy

The following assumptions have been made with respect to carbon policy in the EFC scenario:

- Assume that Climate Change Levy is preserved and remains linked to inflation; *and*

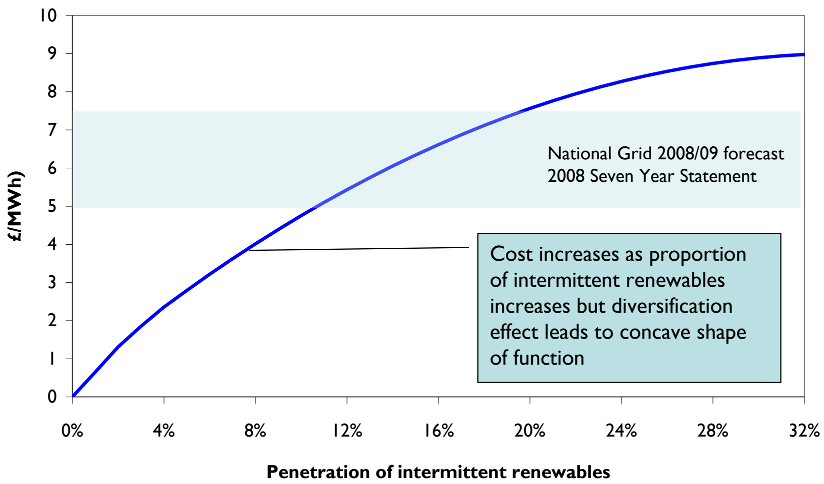
[70] Source: SKM, High Case, RES Strategy Consultation

- Assume full auctioning of EUAs from 2013.

A.2.8 Balancing costs

Figure 42 shows the function used to estimate the additional balancing costs associated with intermittency depending on the proportion of intermittent renewables output.

Figure 42 Balancing cost function[71]



[71] Data is real 2008

A.3 EFC scenario results

This section presents the key modelling results for EFC scenario, showing new build and retirements, carbon dioxide emissions, indicators of security of supply and prices.

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A.3.1 Generation portfolio

In section A.2.5 we set out the committed new build and retirement decisions. In this section we combine these committed decisions with the results of the investment decision modelling. We first summarise the new build decisions that are made endogenously in the modelling and then present the retirement profile of the existing plant.

New build

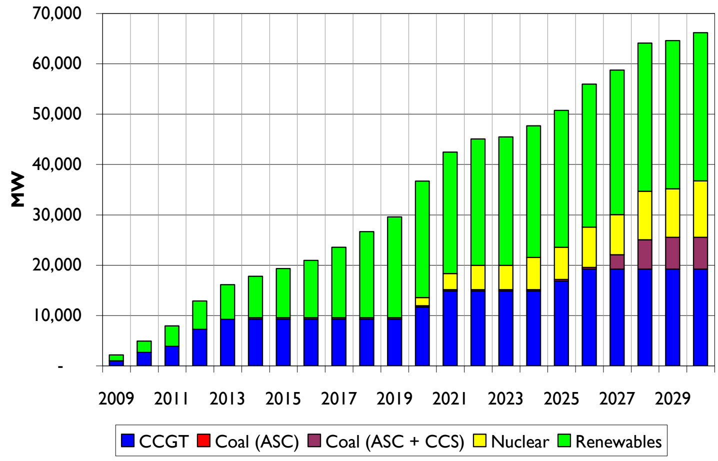
The commodity prices in the EFC scenario present a challenge for investors in fossil fuel plant. In the next decade, on the basis of the CCC's commodity price projections, unabated coal plant has a lower variable generation cost than gas, and would expect to run at baseload levels. There is a load factor risk faced by investors in new CCGT plant. However in the EFC scenario, investors favour CCGT build over coal plant. This is primarily due to the relative ease with which the plant can be built, the lower capital intensity of the plant relative to coal which means they are a more economic option at lower load factors.

Figure 43 shows the cumulative capacity of new plant build in the EFC scenario. This graph includes the committed plant set out in Table 15 and Table 16. By 2015, there is a total of 19.3 GW of new plant commissioned. Of this new build 9.2 GW is new CCGT, 9.8 GW is renewables and there is the 300 MW CCS competition plant. Between 2015 and 2019, no new plant other than renewables is built, and by 2020 there is a total of 23 GW of new renewable capacity which produces 32 percent of total demand. In 2020 the first new nuclear plant is commissioned (1.6 GW) together with the commissioning of 2.4 GW of CCGT, such that the total new build by this point is 36 GW.

After 2020, the CCGT build continues in phases: in 2021, 3.2 GW of CCGT is commissioned, and then 2 GW and 2.4 GW in 2025 and 2026, respectively. A new nuclear reactor (1.6 GW) comes on line every other year, limited by the assumed maximum build rate rather than economics. The first un-subsidised plant fully fitted with CCS plant (2.5 GW) is operational in 2027, with a further 3 GW commissioned in 2028 and 0.5 GW in 2029. Renewables build is steady throughout, but at a slower pace than before 2020. By 2030 there is 30 GW more renewables capacity on the system than today. Wind is the dominant technology, with new build in both onshore and offshore wind comprising around 90 percent of the total 30 GW of new renewables build. The remainder of new build in renewables consists of biomass, and biowaste[72].

[72] In reality, there would likely be a more diverse range of renewables including marine technologies, but for simplicity in this analysis we have assumed that it is biowaste and biomass that are banded up to deliver the target renewables.

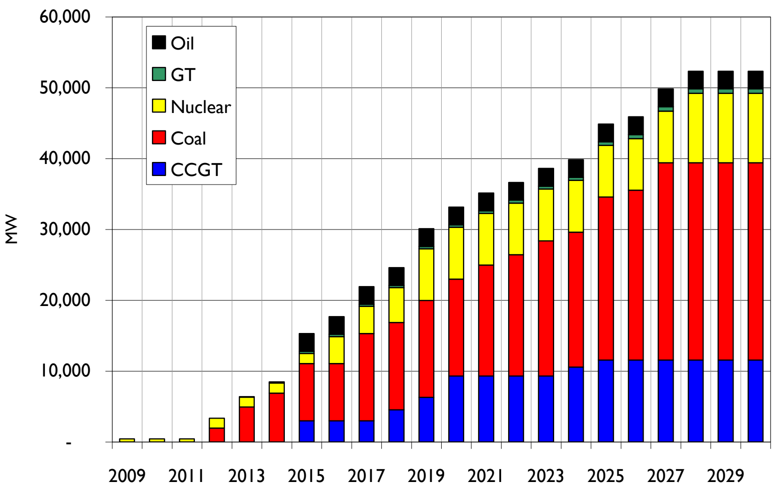
Figure 43 New plant build



Plant retirement

Figure 44 shows the total cumulative retirement by plant type in the EFC scenario. By 2015, approximately 15 GW of plant that is currently on the system has closed. Of this, 11.6 GW is the LCPD opt-out coal and oil plant, and 1.5 GW of nuclear capacity. After 2016 there is a steady retirement of coal plant that did not fit SCR and are operating under a NERP. By 2023 all these coal plant have retired. The high carbon price leads to the retirement of all existing coal plant by 2027, with Drax being the last to close. There is 4 GW of CCGT plant that opted into the NERP post-2015, and these have all retired by 2021. The economics of the EFC scenario move steadily in favour of gas plant relative to coal by the early 2020s, and hence after 2024 there is little further retirement of CCGTs.

Figure 44 Cumulative plant retirements



A.3.2 Generation output and emissions

Figure 45 shows the generation output by fuel type in the EFC scenario. Output from coal rises steadily through to 2015 and then declines thereafter as plant is steadily retired. In 2015, output from coal makes up 34 percent of generation, but falls sharply to 26 percent in 2016, following the remaining LCPD related closures. The decline in coal generation is made up from both gas plant, which rises from 32 percent in 2015 to 39 percent in 2016, and renewables output, which is 17 percent of total output in 2016. By 2020, renewables generate the equivalent of 32 percent of demand and by 2030, 36 percent. Nuclear output initially declines as plant are decommissioned but then grows again once new nuclear plant start coming on-line. It makes up 31 percent of generation by 2030. By then, output from gas plant has dropped to 25 percent having peaked in 2009 at 53 percent[73]. In 2027, the first unsubsidised coal plant with CCS becomes operational and output from CCS plant reaches 11 percent of generation within three years.

Figure 45 Generation output by fuel type

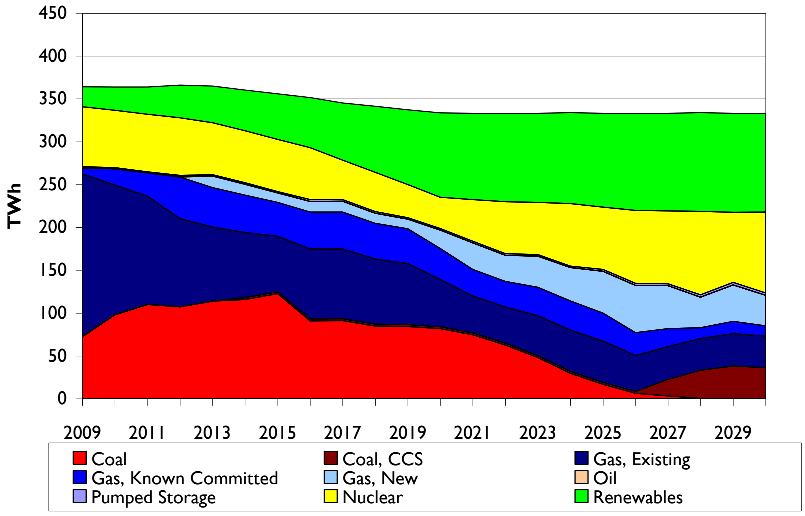


Figure 46 shows that by 2030 total carbon dioxide emissions from the generation sector have dropped by 75 percent from 2009 levels, despite a small upward trend through to 2015 given the increased output from coal plant in this period. The carbon intensity of the generation sector is also shown in Figure 46. By 2030, carbon intensity is 120 g CO_2/kWh. This positions the GB market well on track in terms of achieving a fully decarbonised power sector by 2050.

[73] Gas accounted for 40% of generation in the first-half of 2009.

Figure 46 CO_2 emissions, total and intensity

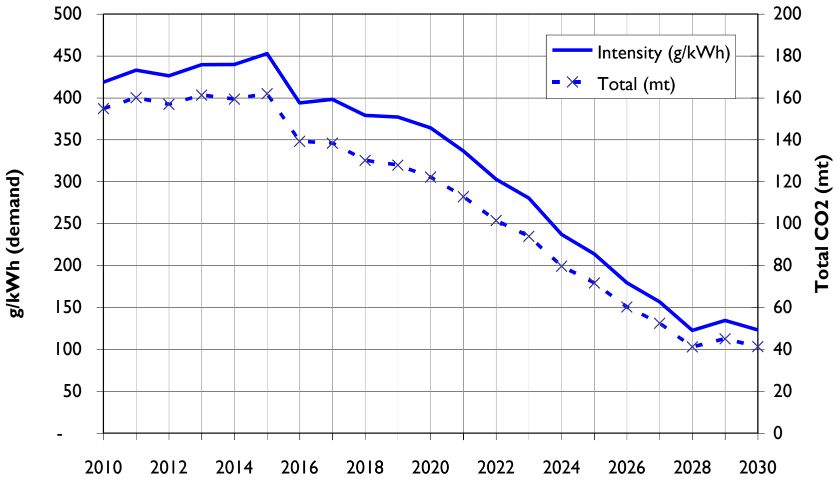
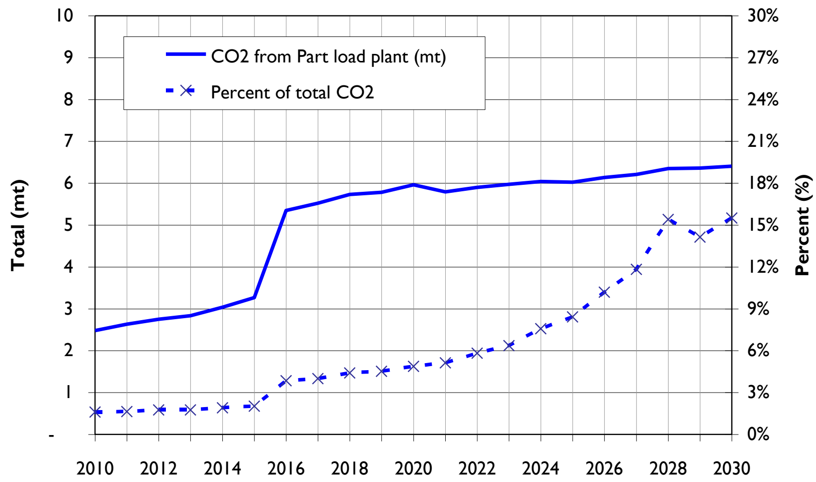


Figure 46 includes CO_2 emissions from part-loaded plant. These plant are assumed to be synchronised and ready to provide generation in the event of sudden changes in plant output (mainly from wind) and / or demand. The required volume of part-loaded plant increases as the installed capacity of wind plant increases. By 2030, emissions from part-loaded plant are 6 mt per annum, or approximately 15 percent of total annual CO_2 emissions from the power sector.

Figure 47 CO_2 emissions from part-loaded thermal plant

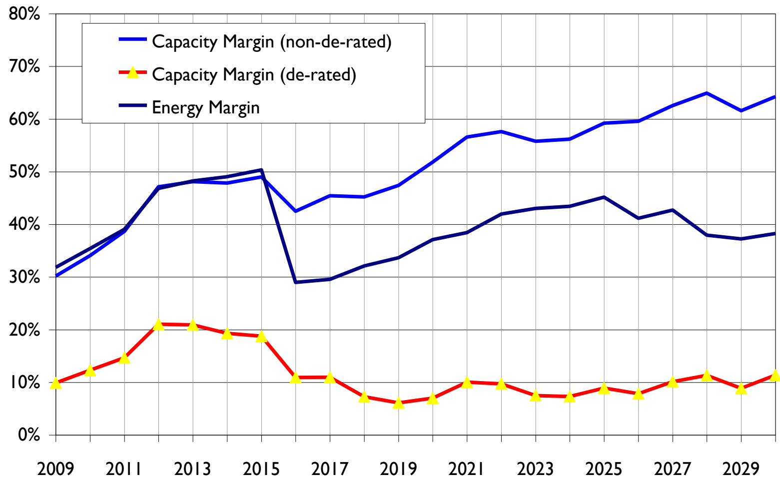


A.3.3 Security of supply

The supply margins in GB will fluctuate with the pattern of new build and retirement and changes in demand. Figure 48 shows the results for the EFC scenario for three different measures of the supply margin:

- Energy Margin: the total annual available energy less annual demand as a percentage of annual demand.
- Capacity Margin (non de-rated): total plant capacity less average peak demand as a percentage of average peak demand.
- De-rated Capacity Margin: as above but applying de-rating factors to capacity to reflect the risk of plant not being fully available at times of peak demand due to forced outages or lack of wind. The de-ratings applied are: Gas and coal - 92 percent; peaking plant - 95 percent; Existing nuclear - 70 percent; New nuclear - 95 percent; Interconnectors - 95 percent. Wind is de-rated through a capacity credit in each year (see Figure 18 for the capacity credit in the EFC scenario).

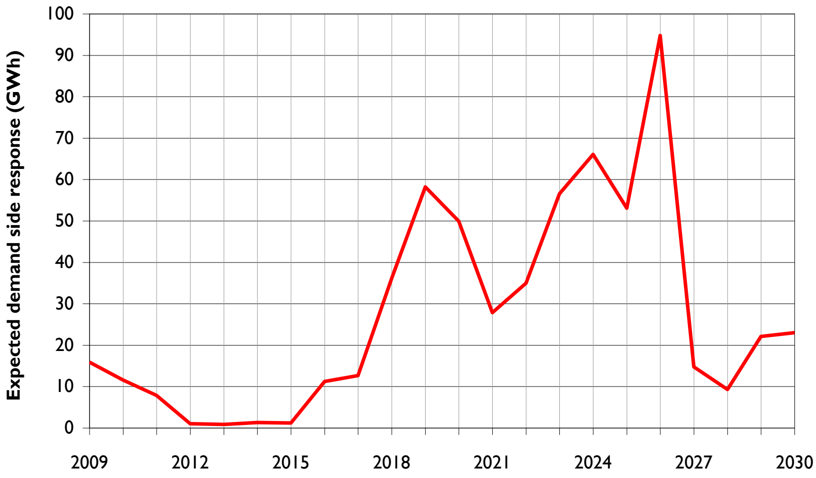
Figure 48 Annual supply margins



Investment in new CCGT plant in anticipation of the LCPD closures can be clearly seen in the rising de-rated capacity margins through to 2012. There is a slight decline to 2015 as some of the coal plant opted-out of the LCPD begin to close having used up their 20,000 running hours. The drop between 2015 and 2016 is caused by the remainder of LCPD opted-out plant closing. After 2015 the energy margin and non de-rated capacity margin generally trend up. However the de-rated capacity margin remains within the range of between 6 to 11 percent through to 2030. The divergence reflects the impact of the declining capacity credit for wind plant as more is added to the system. The result suggests that even with far more capacity on the system overall, security of supply could be similar or somewhat lower than that of today.

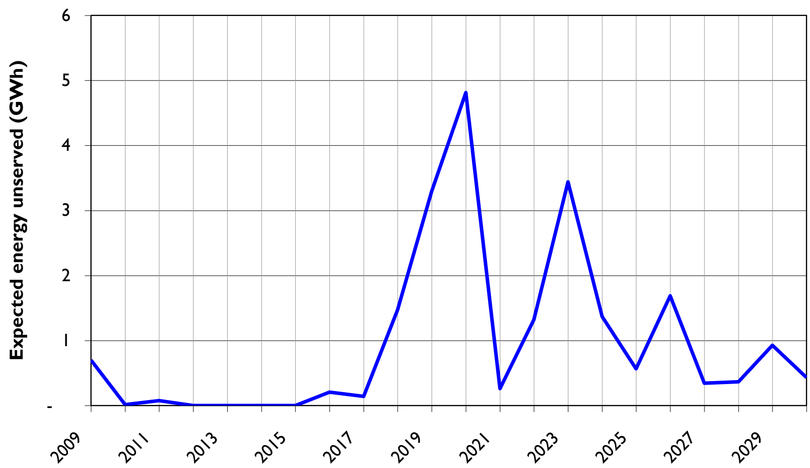
Figure 49 shows the expected Demand Side Response (DSR) in each year of the EFC scenario.

Figure 49 Expected demand side response



Expected energy unserved is shown in Figure 50.

Figure 50 Expected energy unserved



A.3.4 Prices

Figure 51 shows the annual wholesale prices alongside the short run costs of the marginal plant on the system.

Figure 51 Annual baseload prices and system short run marginal cost

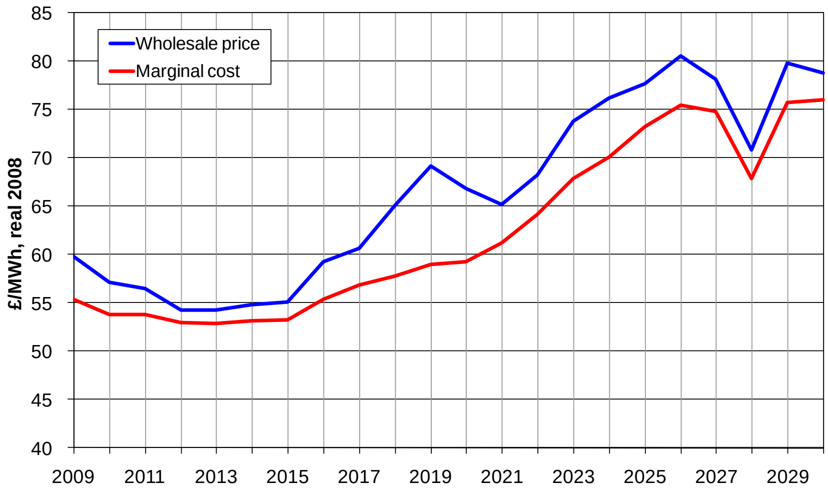
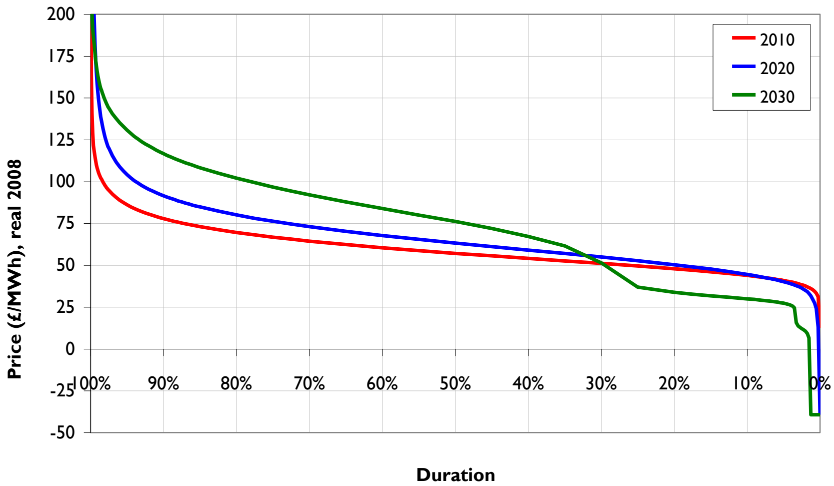


Figure 52 shows the price duration curves for 2010, 2020 and 2030.

Figure 52 Price duration curves



B Sensitivities

In this Appendix we present a high level summary of each of the sensitivities and a comparison with the Environmentally Favourable Conditions (EFC) reference case. In each sensitivity we set out the key question being addressed; the change in assumptions relative to the EFC scenario and the key outcomes. In each sensitivity we present with a key metrics table and a set of charts.

The key metrics presented for both 2020 and 2030 are:

- **Cumulative capacity, MW** – shown for renewables, nuclear, CCGT, CCS and unabated coal.
- **Total CO_2 emissions, mt CO_2** - all emissions from the power sector, quoted to the nearest tonne.
- **CO_2 intensity g CO_2/kWh** - power sector emissions per kWh of metered demand, quoted to two significant figures.
- **Wholesale cost to consumer, £/MWh** - this is the sum of the variable and non-variable operating costs, capital cost recovered and any subsidy paid by consumers to generators.
- **Spill, GWh** - the annual volume of generation which has to be constrained off to match supply and demand.
- **Energy unserved, GWh** - the total annual involuntary demand reduction.
- **De-rated capacity margin, % -** average in the preceeding five years. A security of supply measure: it is the gap between peak load and probabilistic evaluation of available capacity at peak time.
- **Net Present Value (NPV) of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million** - this value is only presented in sensitivities which have the same commodity assumptions as the EFC.

The charts presented are:

- Build profile by capacity type (MW)
- Generation by capacity type (TWh)
- Annual average demand-weighted wholesale prices (£/MWh)
- De-rated capacity margin (%)
- Total CO_2 emissions (mt)
- Emission intensity (g CO_2/kWh)
- Probability density function of prices (years 2010, 2020 and 2030)

REDPOINT

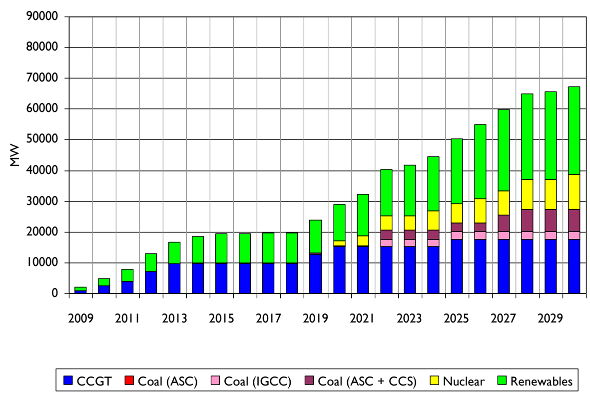
B.1 Severn Barrage (1-SB)

The Question: How does building the Severn Barrage impact on security of supply, emissions and electricity prices?

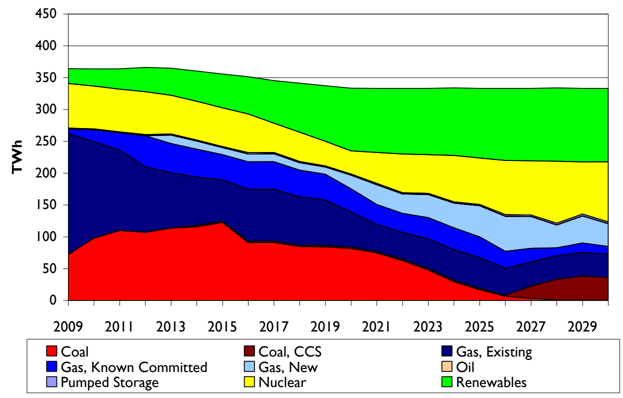
The Assumptions: The 8.6 GW Cardiff-Weston Severn Barrage is commissioned in 2022, and contributes to the 2020 renewable generation target.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	12.0	23.2	37.2	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	15.2	11.6	17.6	19.2
Total CCS build (GW)	0.3	0.3	7.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	132	117	38	40
CO_2 intensity, g CO_2/kWh (demand)	390	350	110	120
Wholesale costs to consumer, £/MWh	81.2	94.7	95.3	108.0
Spill, GWh	0.00	0.00	0.77	0.35
Energy unserved, GWh	0.2	4.8	0.8	0.4
De-rated capacity margin, average in preceding five years, %	10.4	8.5	9.8	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-957	

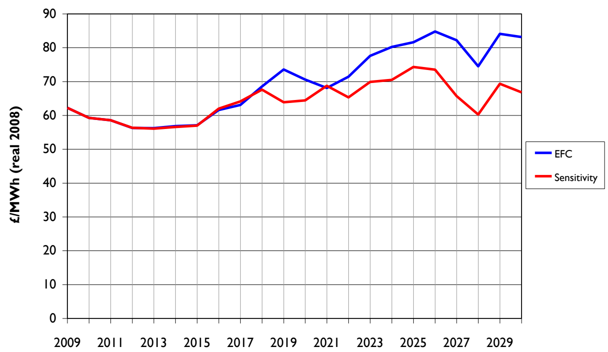
Build profile



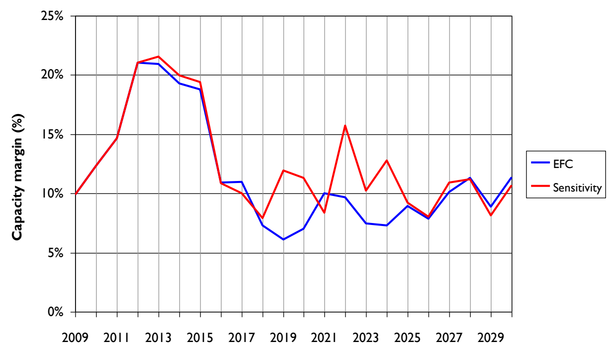
Generation, TWh



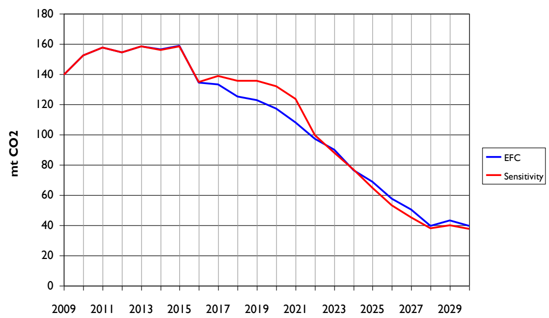
Annual average demand-weighted prices



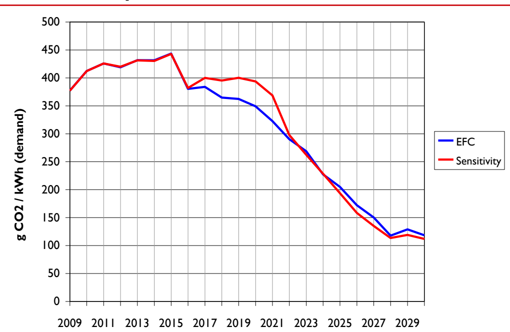
Capacity margin



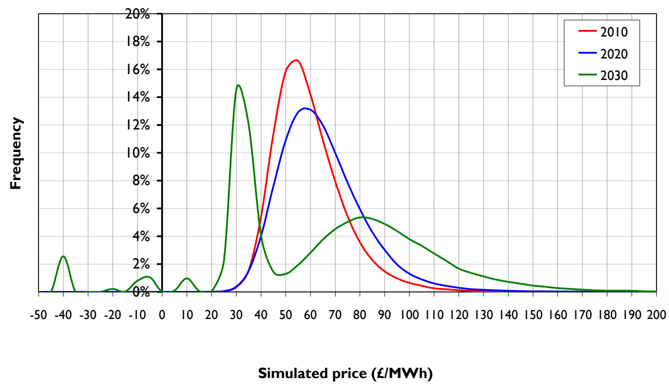
Total CO_2 emissions



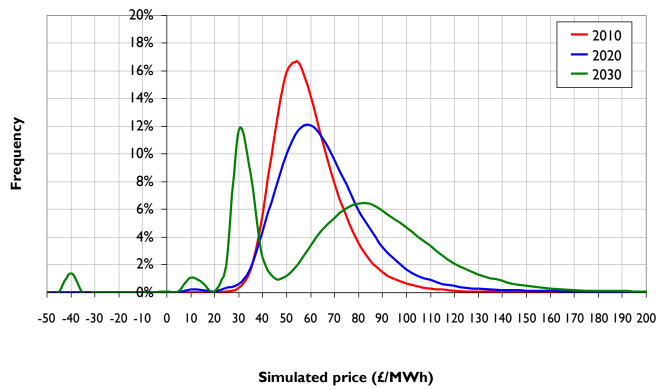
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



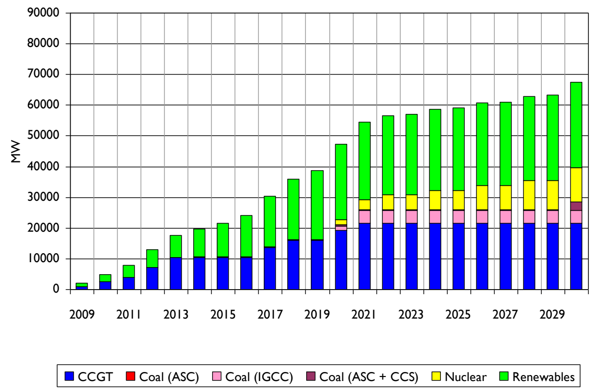
B.2 Peak prices dampened (2-PP)

The Question: If prices are unable to sufficiently peak to reflect full scarcity value, will investment in thermal plant be jeopardised?

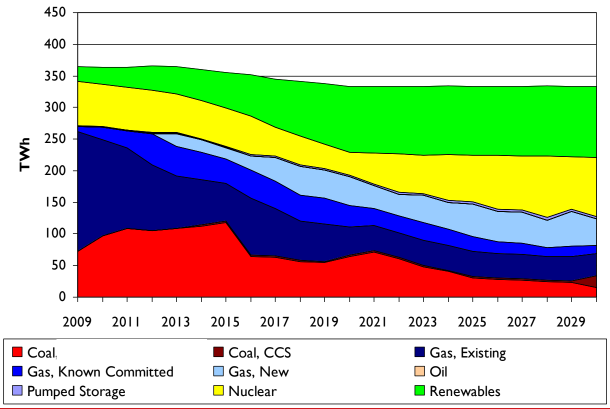
The Assumptions: An assumption that market rules prevent peak prices rising above 500 £/MWh even in periods where the marginal value of electricity is greater.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	12.0	23.2	37.2	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	15.2	11.6	17.6	19.2
Total CCS build (GW)	0.3	0.3	7.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	104	117	51	40
CO_2 intensity, g CO_2/kWh (demand)	110	350	150	120
Wholesale costs to consumer, £/MWh	91.8	94.7	118.4	108.0
Spill, GWh	0.00	0.00	0.28	0.35
Energy unserved, GWh	0.8	4.8	1.0	0.4
De-rated capacity margin, average in preceding five years, %	8.2	8.5	7.6	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-9,662	

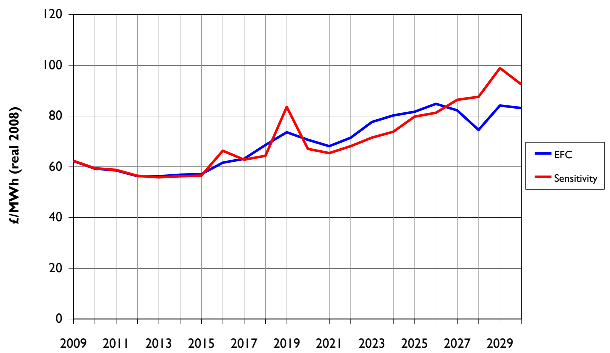
Build profile



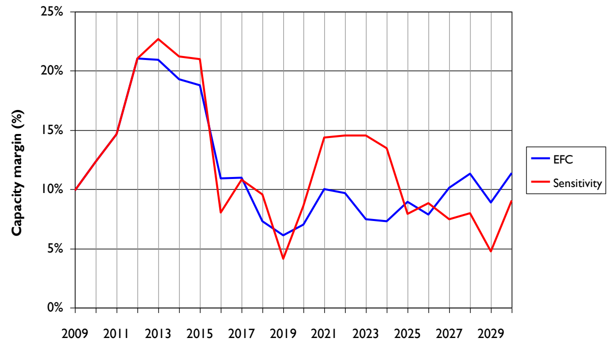
Generation, TWh



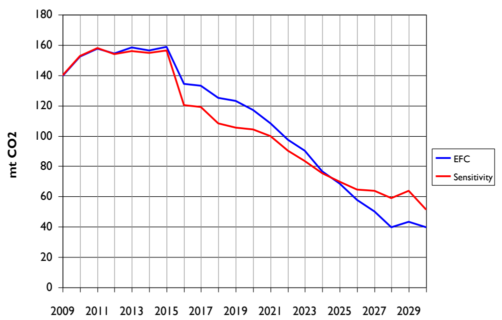
Annual average demand-weighted prices



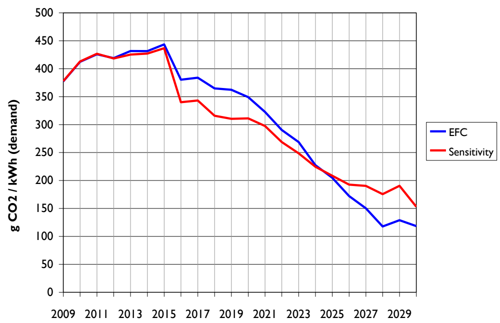
Capacity margin



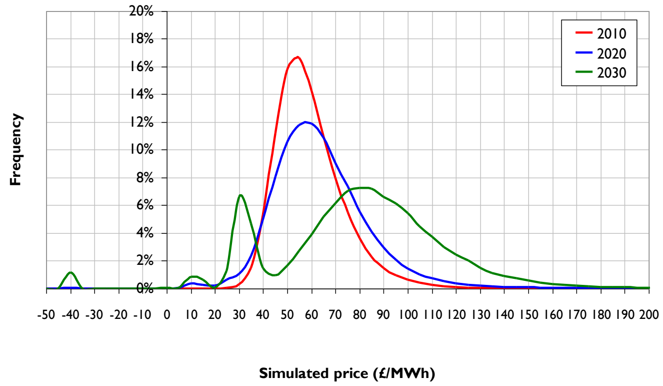
Total CO2 emissions



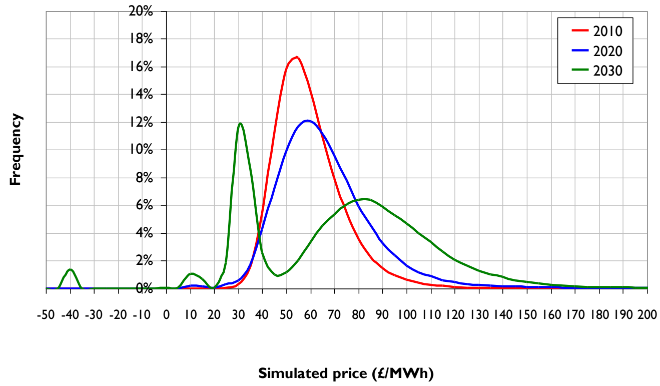
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

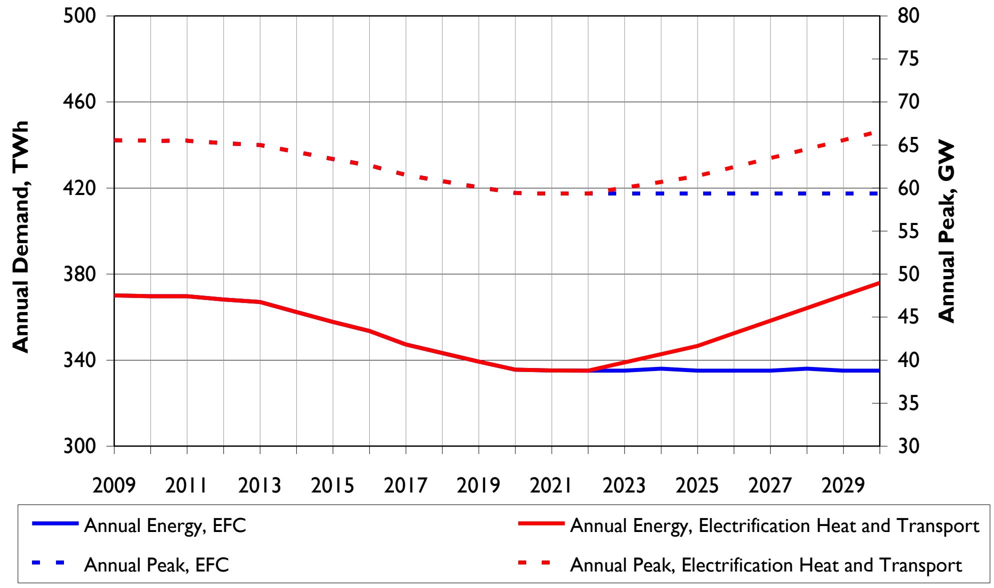


B.3 Electrification of the heat and transport sector, peak and offpeak hours (3-EP)

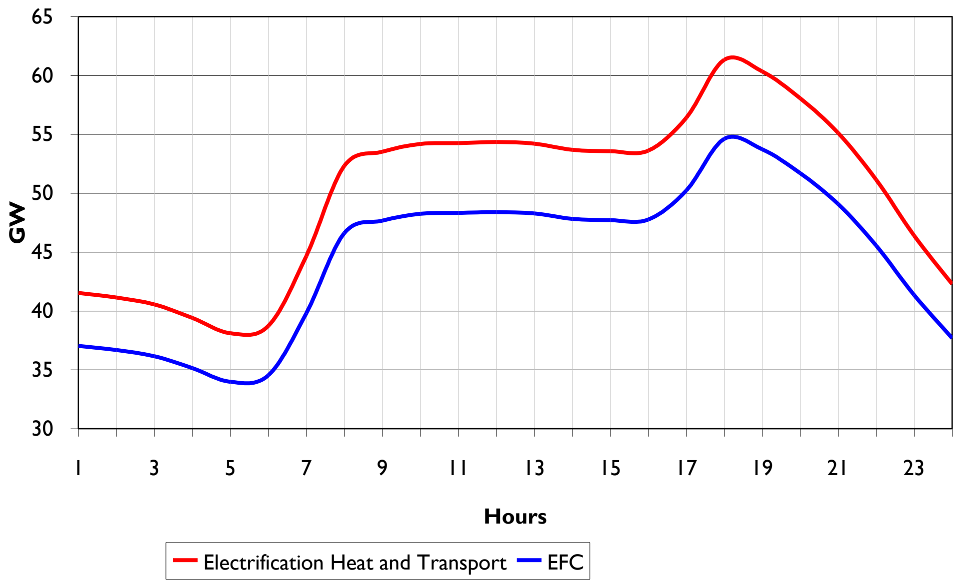
The Question: What is the impact of increasing electrification of the heat and transport sector with the increase in demand across all hours of the day?

The Assumptions: Demand per the EFC scenario through to 2022 (falling from 370 TWh in 2009 to 335 TWh, in 2020 and constant through to 2022); demand then rises from 2023 to 376 TWh in 2030. The daily demand shape remains unchanged, so that demand in the peak and offpeak hours are changing at the same rate; the corresponding peaks are 66 GW in 2009, 59 GW in 2020 and 67 GW in 2030.

Peak and Annual Demand

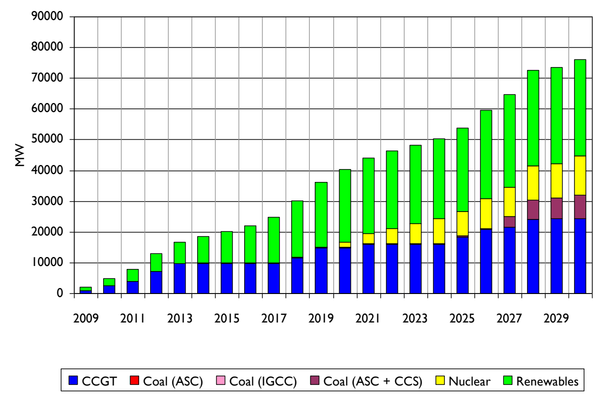


Daily Demand Shape

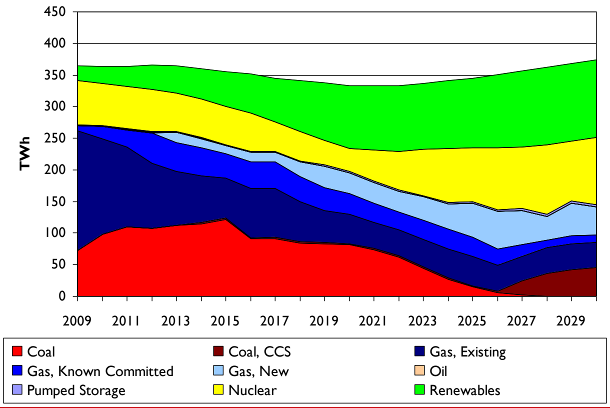


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.7	23.2	31.2	29.5
Total nuclear build (GW)	1.6	1.6	12.8	11.2
Total CCGT build (GW)	14.8	11.6	24.4	19.2
Total CCS build (GW)	0.3	0.3	7.6	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	116	117	44	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	120	120
Wholesale costs to consumer, £/MWh	88.49	94.67	110.40	108.03
Spill, GWh	0.00	0.00	0.25	0.35
Energy unserved, GWh	0.7	4.8	0.0	0.4
De-rated capacity margin, average in preceding five years, %	12.4	8.5	9.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-8,808	

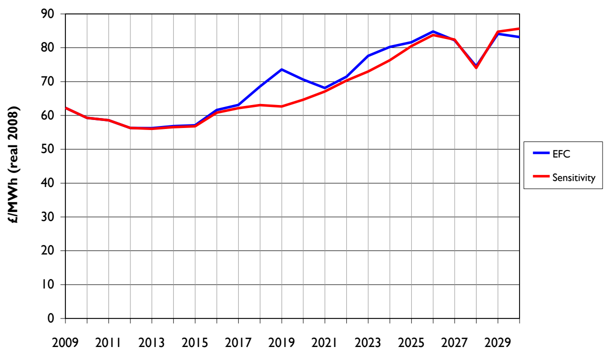
Build profile



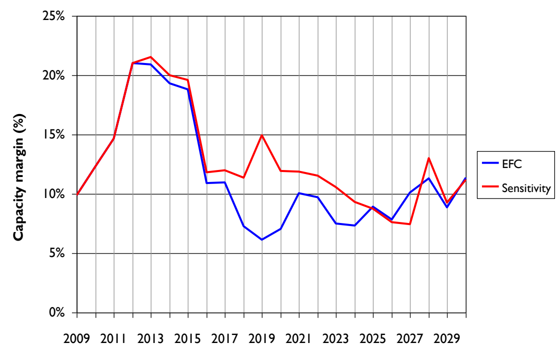
Generation, TWh



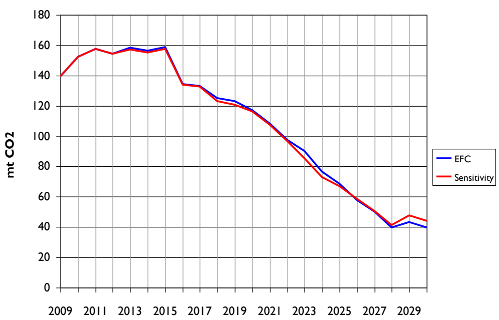
Annual average demand-weighted prices



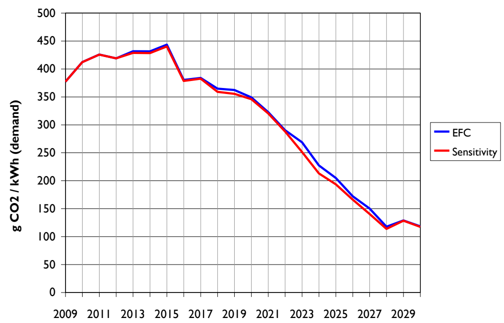
Capacity margin



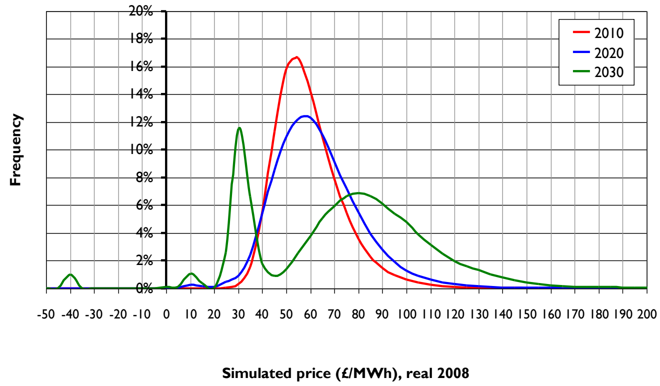
Total CO_2 emissions



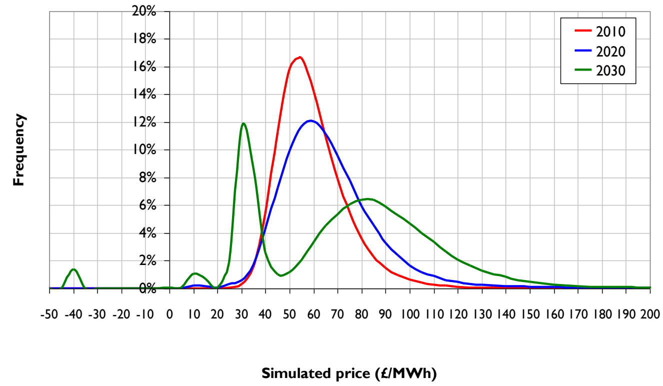
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

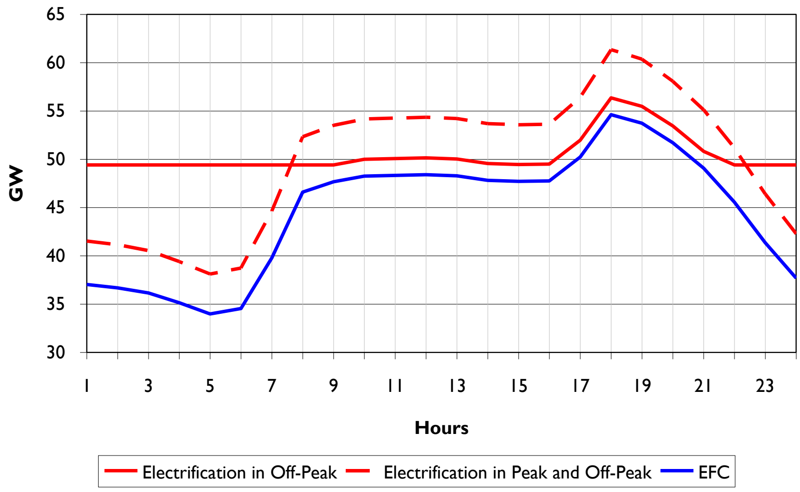


B.4 Electrification of the heat and transport sector, offpeak hours only (4-EO)

The Question: What is the impact of increasing electrification of the heat and transport sector with the increase in demand targeted at offpeak hours only?

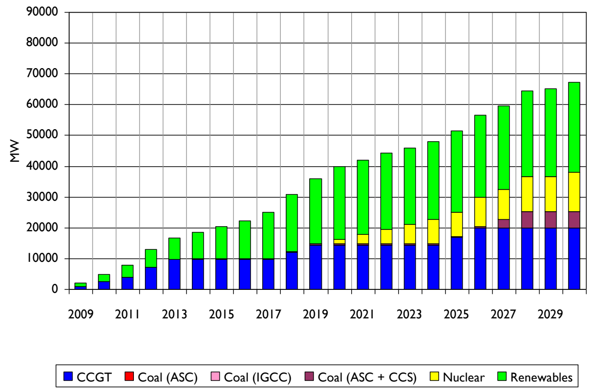
The Assumptions: Total annual energy demand is as in the Electrification of the heat and transport sector sensitivity (3-EP). However, growth occurring from 2023 occurs first in the offpeak hours. At the point when the demand profile is flat across the day (the offpeak and peak hours are at the same level), demand grows across the entire day. This produces a flatter daily demand profile than the previous case.

Figure 53 Average daily demand shape (Electrification cases

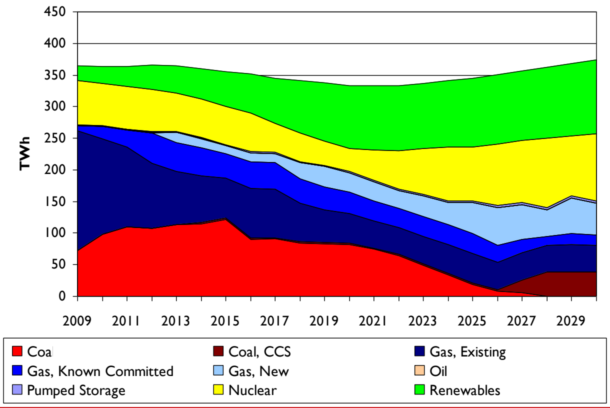


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.5	23.2	29.1	29.5
Total nuclear build (GW)	1.6	1.6	12.8	11.2
Total CCGT build (GW)	14.4	11.6	20.0	19.2
Total CCS build (GW)	0.3	0.3	5.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	116	117	49	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	130	120
Wholesale costs to consumer, £/MWh	88.7	94.7	130.8	108.0
Spill, GWh	0.00	0.00	0.05	0.35
Energy unserved, GWh	0.3	4.8	4.0	0.4
De-rated capacity margin, average in preceding five years, %	11.7	8.5	11.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-5,663	

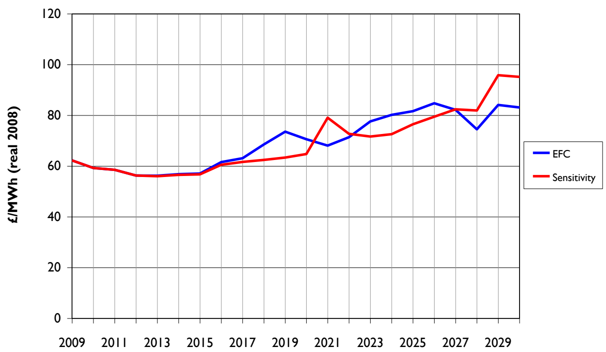
Build profile



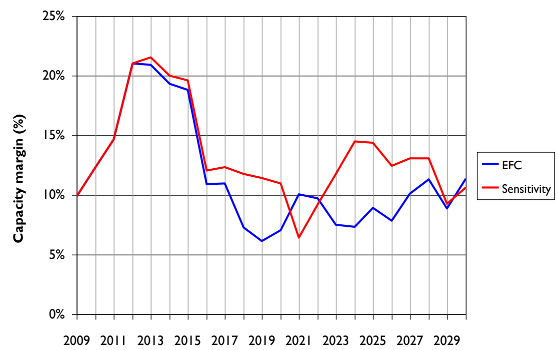
Generation, TWh



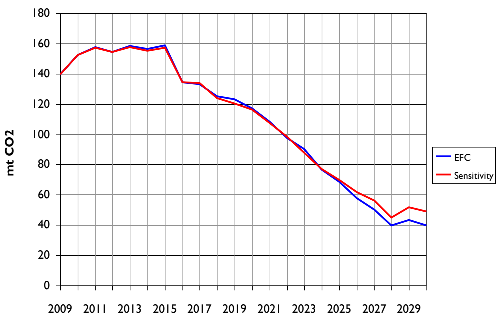
Annual average demand-weighted prices



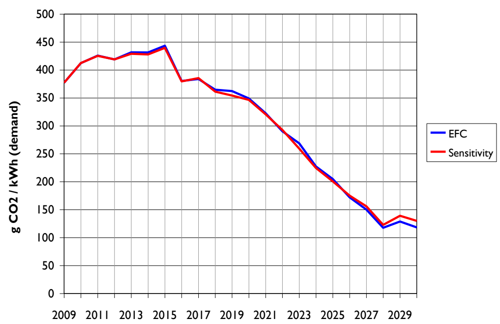
Capacity margin



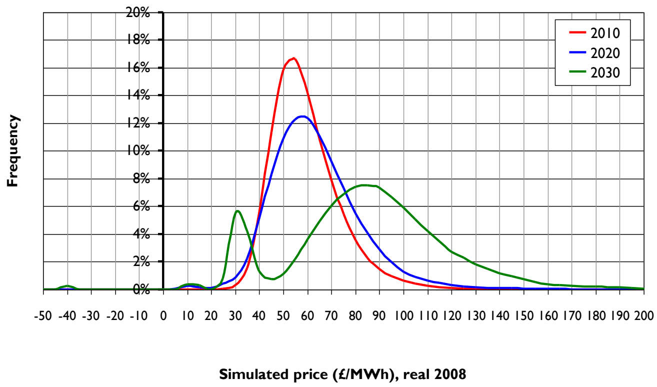
Total CO_2 emissions



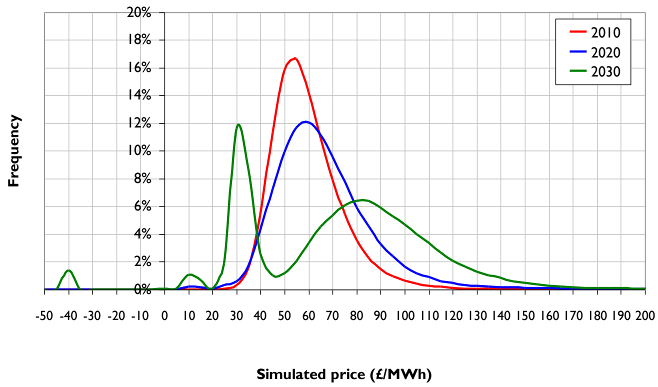
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



B.5 Low renewable generation (5-LR)

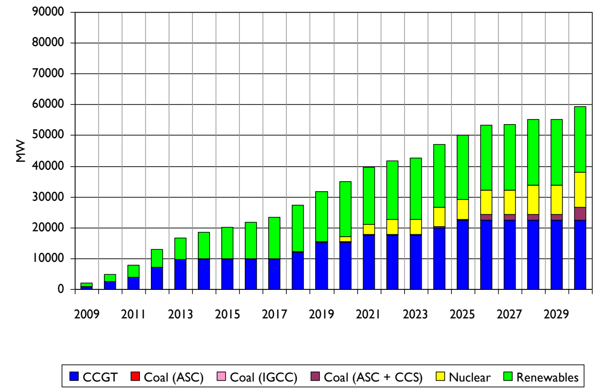
The Question: What is the impact of a lower renewable generation target?

The Assumptions: The renewable generation target is set to 25 percent rather than 32 percent of demand. This is achieved by reducing the ROC bands post 2013.

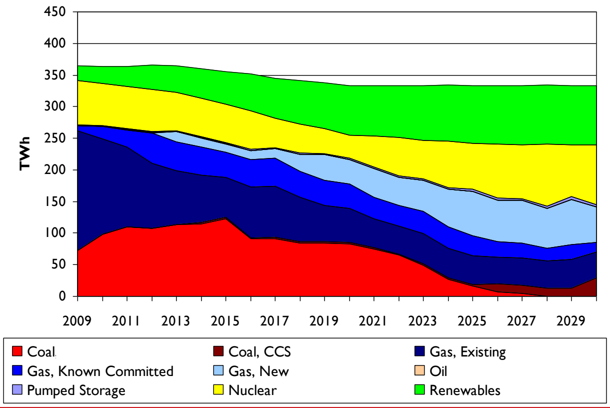
	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	17.9	23.2	21.3	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	15.2	11.6	22.4	19.2
Total CCS build (GW)	0.3	0.3	4.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	125	117	49	40
CO_2 intensity, g CO_2/kWh (demand)	370	350	150	120
Wholesale costs to consumer, £/MWh	85.4	94.7	117.9	108.0
Spill, GWh	0.00	0.00	0.02	0.35
Energy unserved, GWh	0.7	4.8	0.2	0.4
De-rated capacity margin, average in preceding five years, %	11.2	8.5	9.5	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			5,875	

REDPOINT

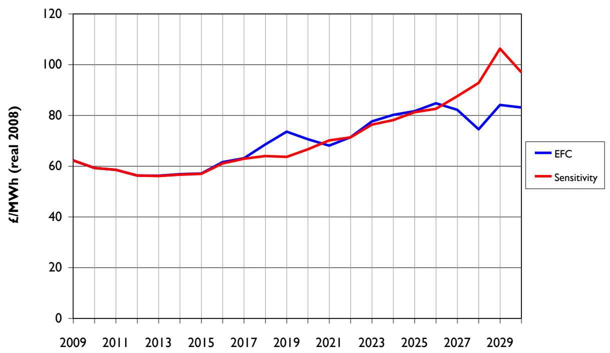
Build profile



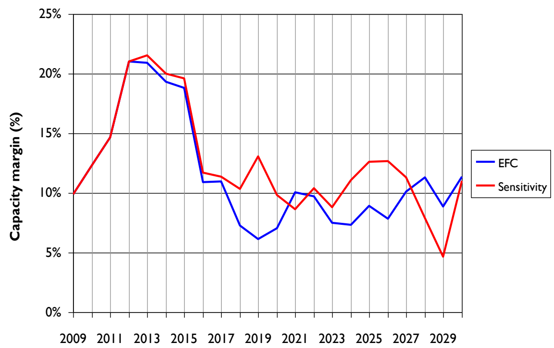
Generation, TWh



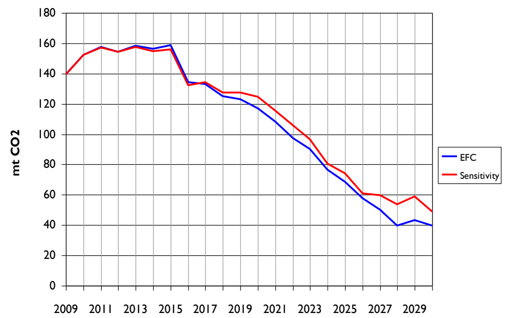
Annual average demand-weighted prices



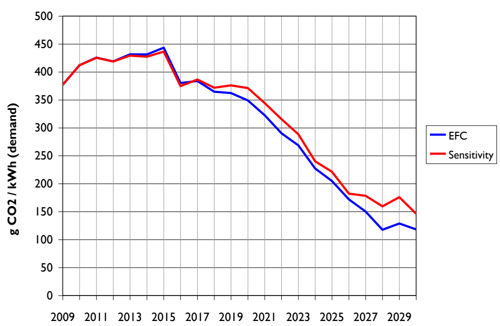
Capacity margin



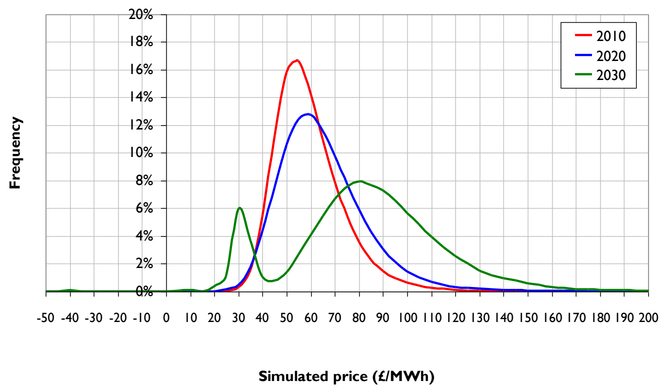
Total CO_2 emissions



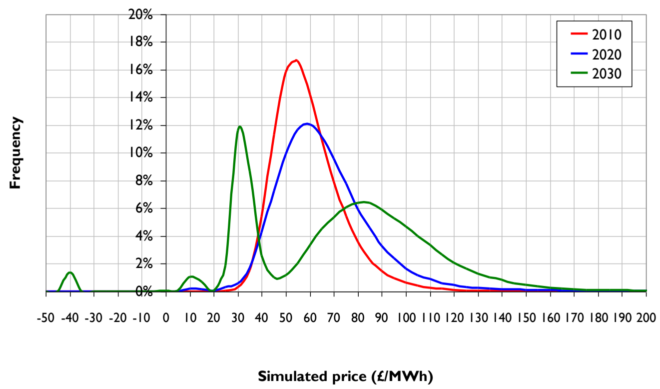
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



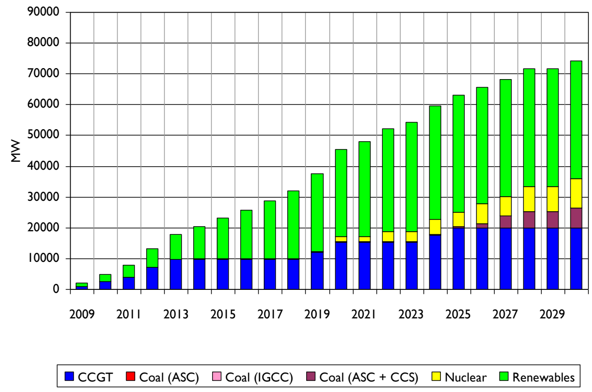
B.6 High renewable generation (6-HR)

The Question: What is the impact of a higher renewable generation target?

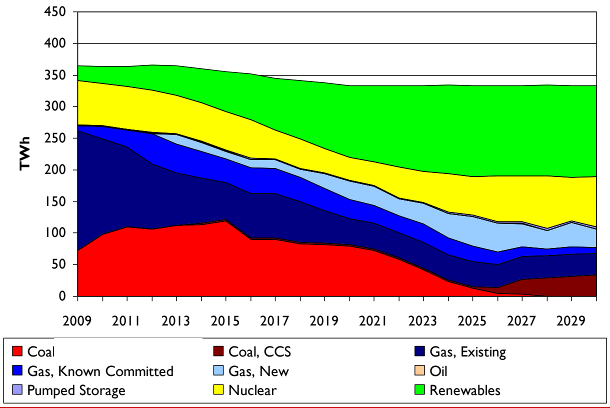
The Assumptions: ROC banding is set so that renewables build is constrained by a maximum build rate assumption rather than the economics of investment.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	28.2	23.2	38.4	29.5
Total nuclear build (GW)	1.6	1.6	9.6	11.2
Total CCGT build (GW)	15.2	11.6	20.0	19.2
Total CCS build (GW)	0.3	0.3	6.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	110	117	36	40
CO_2 intensity, g CO_2/kWh (demand)	330	350	110	120
Wholesale costs to consumer, £/MWh	93.7	94.7	113.8	108.0
Spill, GWh	0.03	0.00	1.93	0.35
Energy unserved, GWh	0.2	4.8	3.5	0.4
De-rated capacity margin, average in preceding five years, %	12.0	8.5	8.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-18,737	

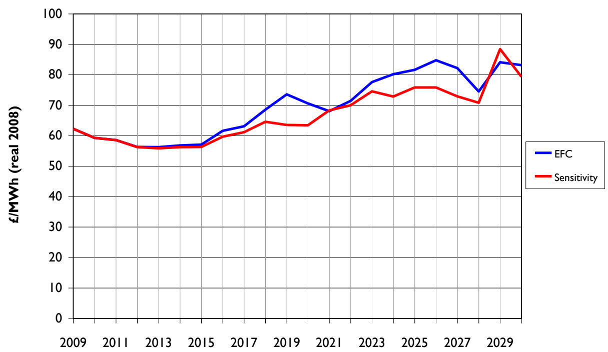
Build profile



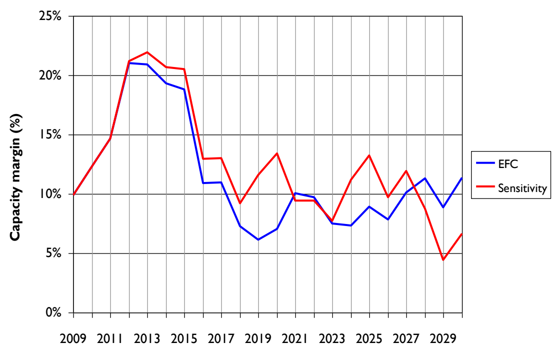
Generation, TWh



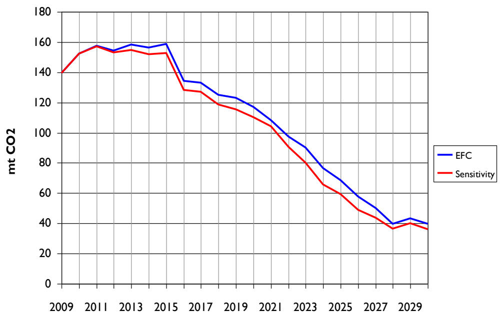
Annual average demand-weighted prices



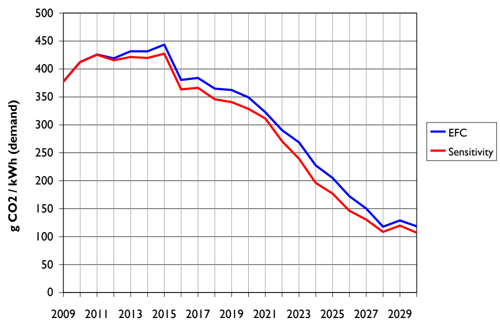
Capacity margin



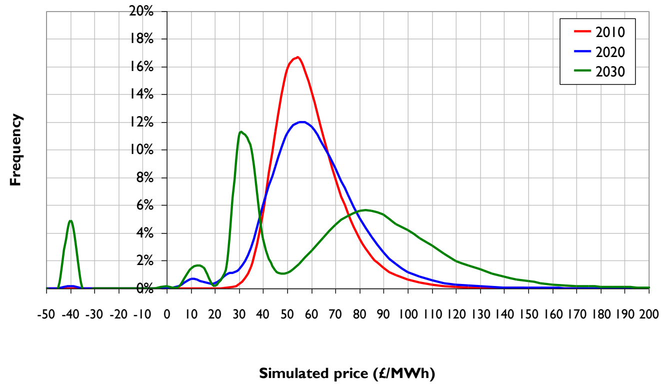
Total CO_2 emissions



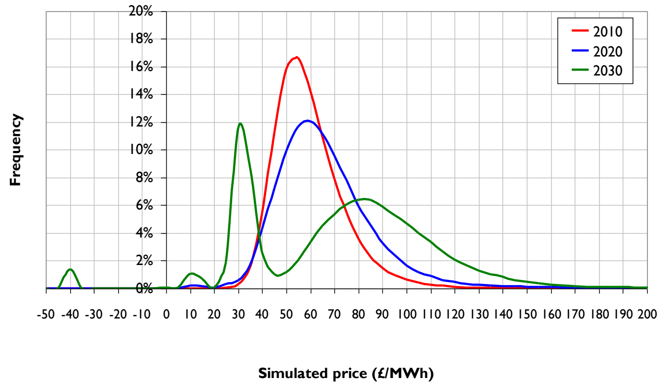
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



B.7 Low renewable generation and Offpeak electrification of the heat and transport electrification (7-LR-EO)

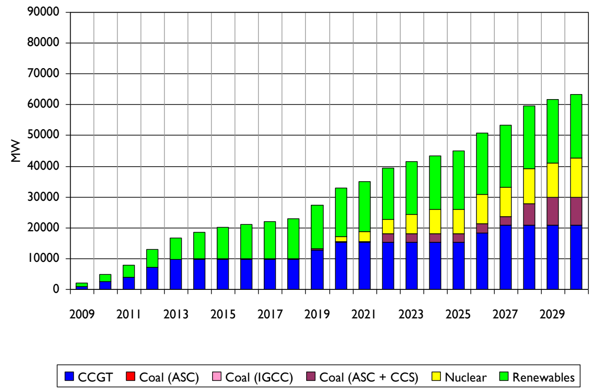
The Question: What is the combined impact of a lower renewable generation target and electrification of the heat and transport sector post 2023 in the offpeak hours?

The Assumptions: The renewable generation target is set to 25 percent (5-LR). Demand is as per electrification of the heat and transport sector in the offpeak hours (4-EO)).

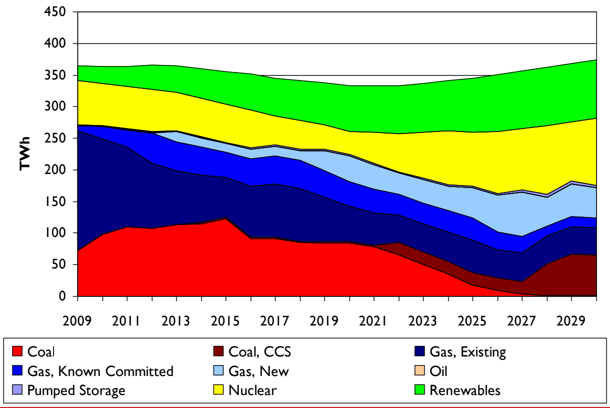
	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	15.8	23.2	20.5	29.5
Total nuclear build (GW)	1.6	1.6	12.8	11.2
Total CCGT build (GW)	15.2	11.6	20.8	19.2
Total CCS build (GW)	0.3	0.3	9.1	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	127	117	48	40
CO_2 intensity, g CO_2/kWh (demand)	380	350	130	120
Wholesale costs to consumer, £/MWh	86.81	94.7	119.1	108.03
Spill, GWh	0.00	0.00	0.00	0.35
Energy unserved, GWh	1.4	4.8	0.2	0.4
De-rated capacity margin, average in preceding five years, %	8.6	8.5	13.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			3,568	

- Although total investment is lower than with EFC and higher than in Low renewable generation, the average de-rated capacity margin is higher across both given greater reliance on non intermittent generation.

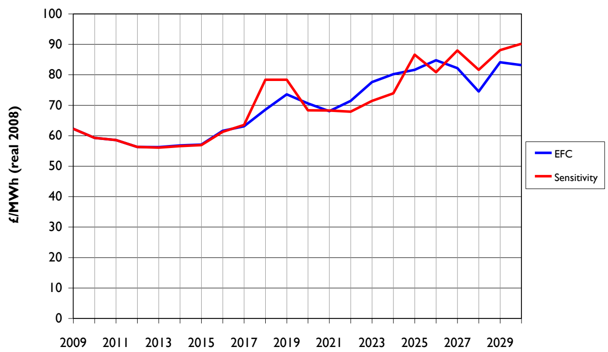
Build profile



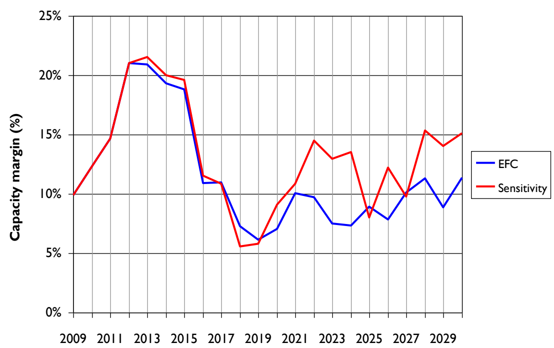
Generation, TWh



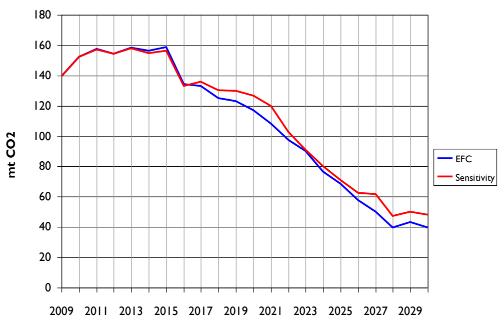
Annual average demand-weighted prices



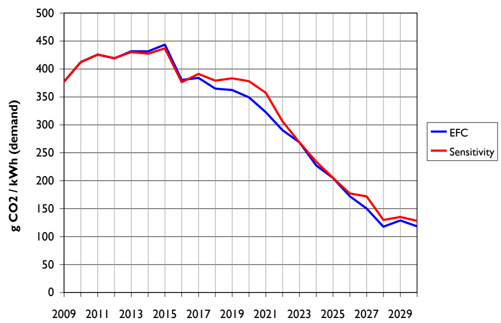
Capacity margin



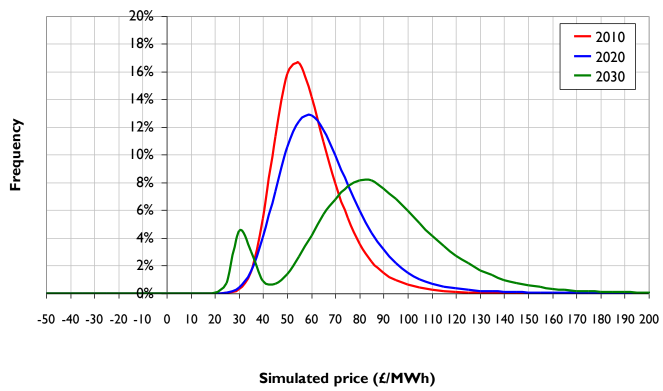
Total CO_2 emissions



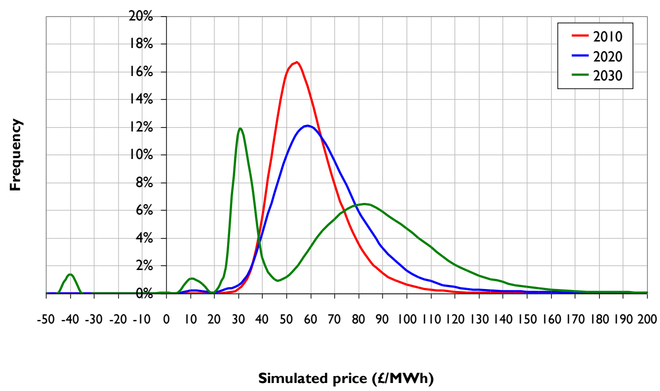
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



B.8 Reduced interconnector flexibility (8-LI)

The Question: What is the impact on spill if intermittent output is more highly correlated with intermittent output on the Continent, which would reduce the ability to mitigate spill through exporting?

The Assumptions: The maximum available export capacity is reduced to 1.0 GW from 3.3 GW.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.7	23.2	27.7	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	14.8	11.6	20.4	19.2
Total CCS build (GW)	0.3	0.3	4.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	116	117	44	40
CO_2 Intensity, g CO_2/kWh (demand)	350	350	130	120
Wholesale costs to consumer, £/MWh	135	94.67	158.80	108.03
Spill, GWh	0.01	0.00	0.46	0.35
Energy Unserved, GWh	0.7	4.8	0.5	0.4
De-rated capacity margin, average in preceding five years, %	12.4	8.5	10.1	9.9
NPV of Change in Resource Cost, excluding the cost of CO_2, relative to the EFC, £ million			-1,168	

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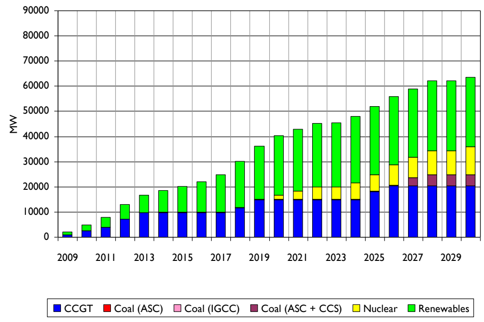
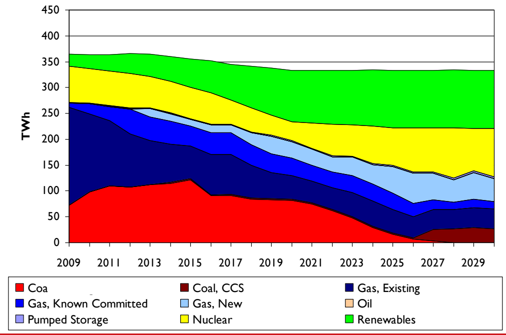
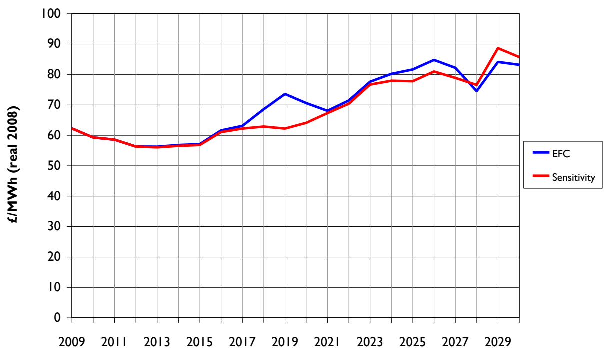
Build profile



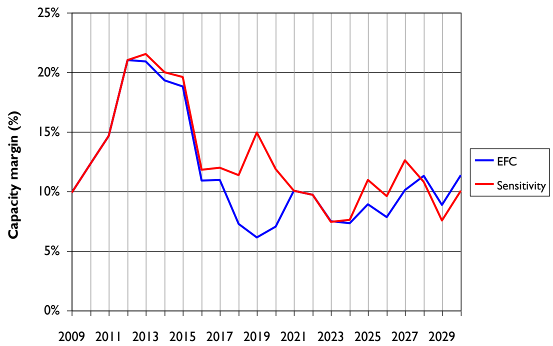
Generation, TWh



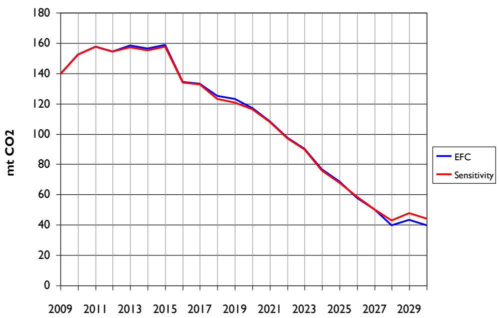
Annual average demand-weighted prices



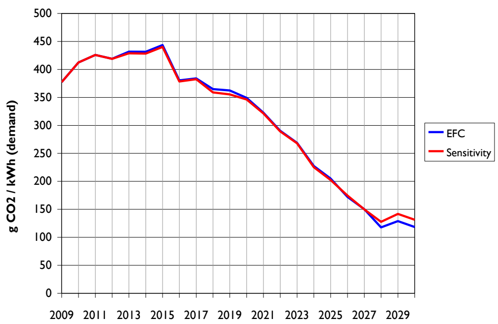
Capacity margin



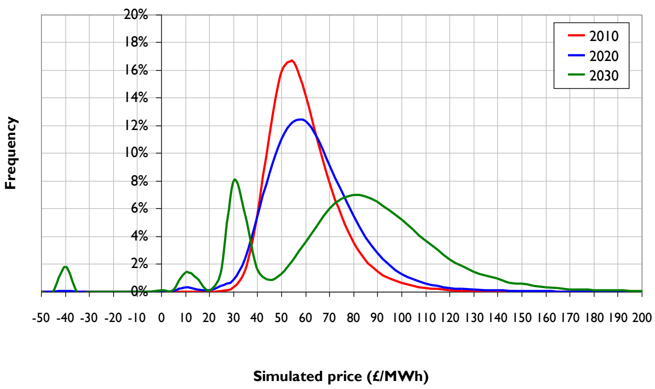
Total CO_2 emissions



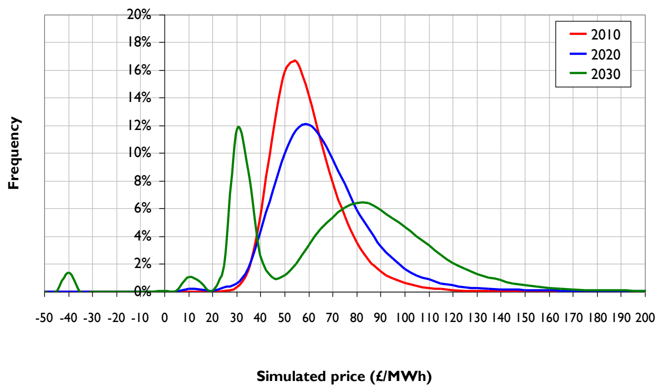
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



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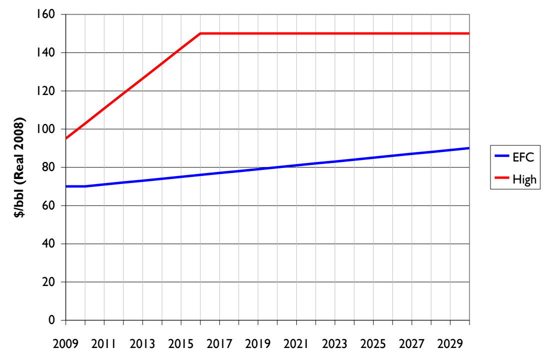
B.9 High fossil fuel prices (9-HF)

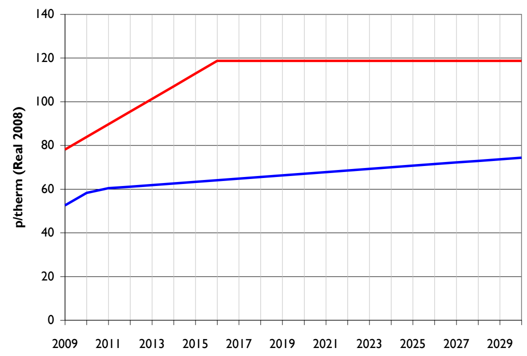
The Question: How do higher commodity prices impact on the results?

The Assumptions: See graphs below.

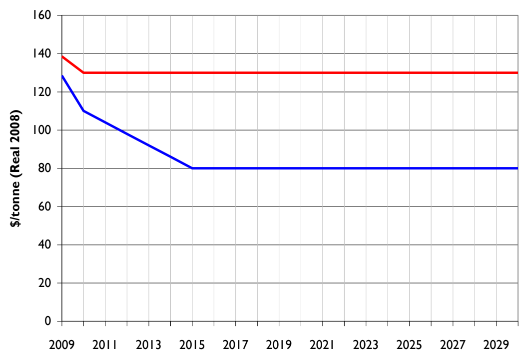
Oil



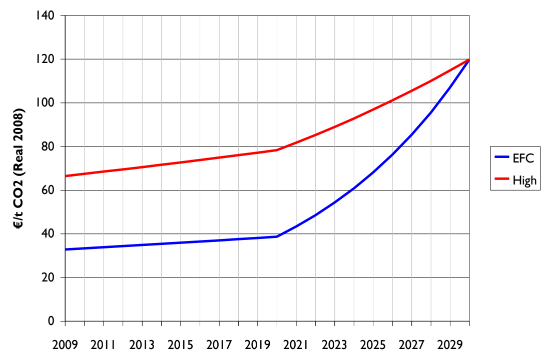
Gas



Coal



EUA



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	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	25.2	23.2	28.1	29.5
Total nuclear build (GW)	1.6	1.6	16.0	11.2
Total CCGT build (GW)	16.0	11.6	16.0	19.2
Total CCS build (GW)	2.0	0.3	7.6	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	103	117	38	40
CO_2 intensity, g CO_2/kWh (demand)	310	350	110	120
Wholesale costs to consumer, £/MWh	133.9	94.7	97.5	108.0
Spill, GWh	0.01	0.00	0.83	0.35
Energy unserved, GWh	0.0	4.8	1.8	0.4
De-rated capacity margin, average in preceding five years, %	15.3	8.5	7.9	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

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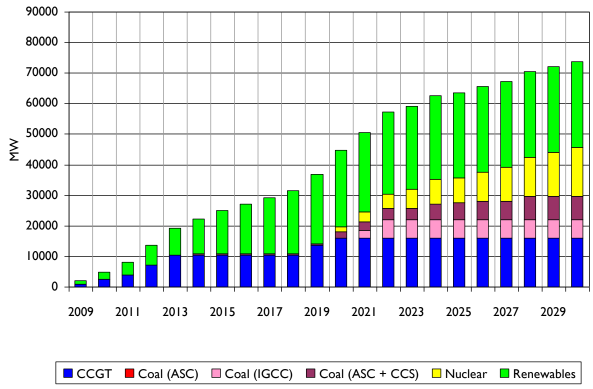
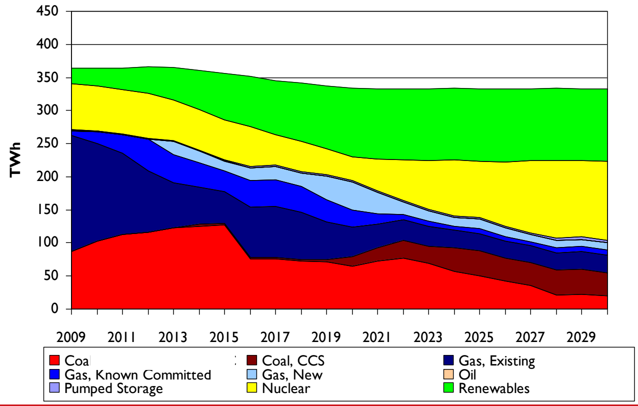
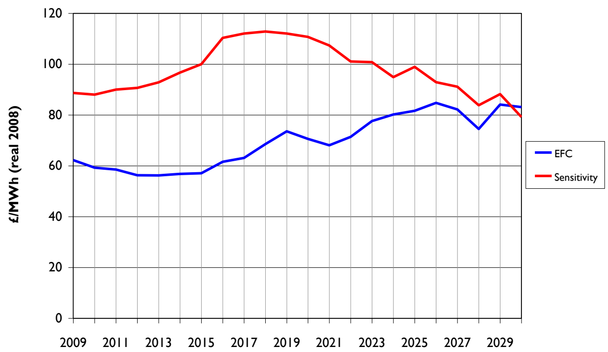
Build profile



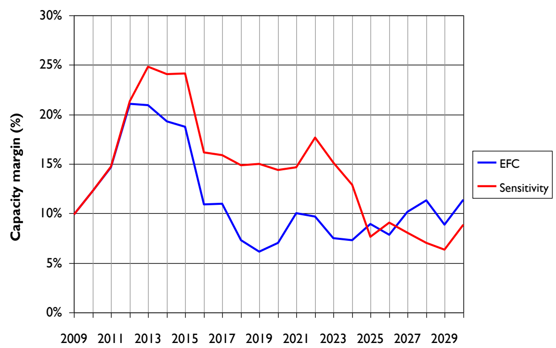
Generation, TWh



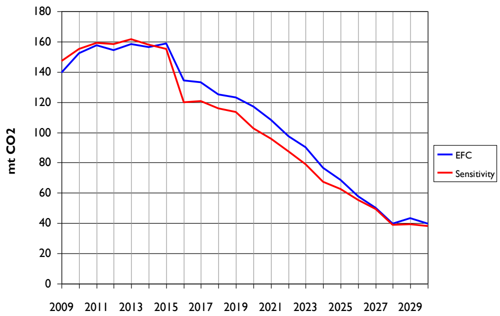
Annual average demand-weighted prices



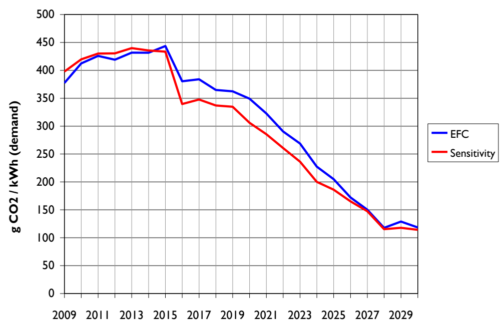
Capacity margin



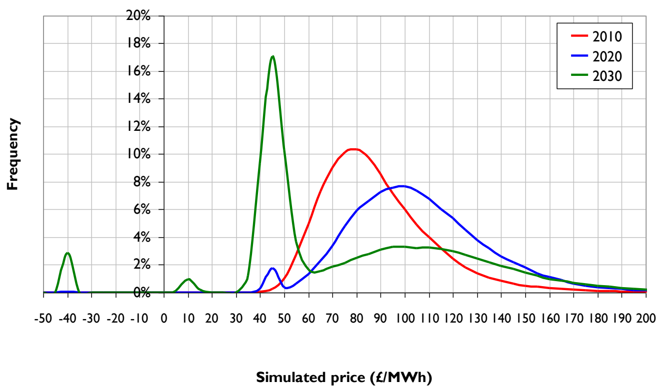
Total CO_2 emissions



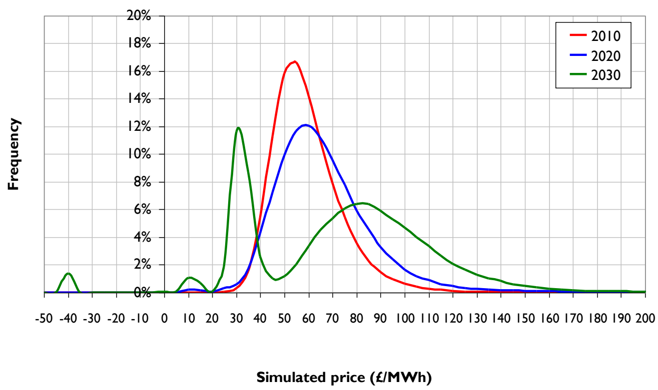
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

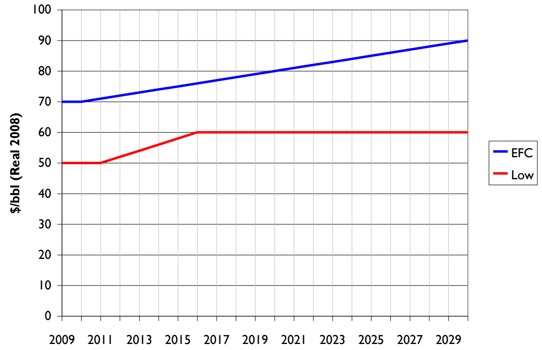


B.10 Lower fossil fuel prices (10-LF)

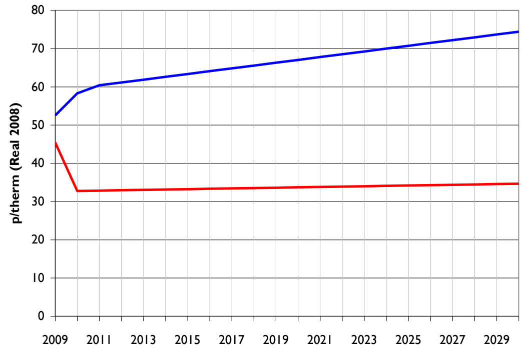
The Question: How do lower commodity prices impact on the results?

The Assumptions: See graphs below.

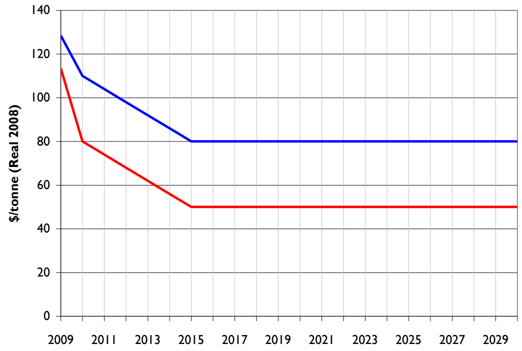
Oil



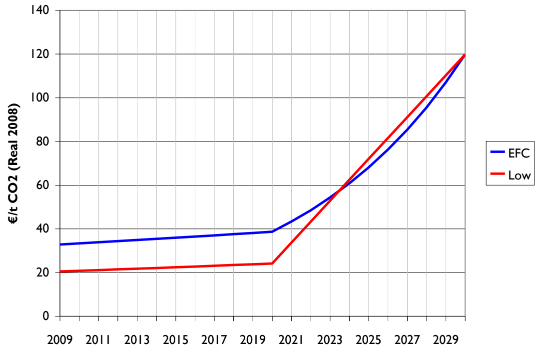
Gas



Coal

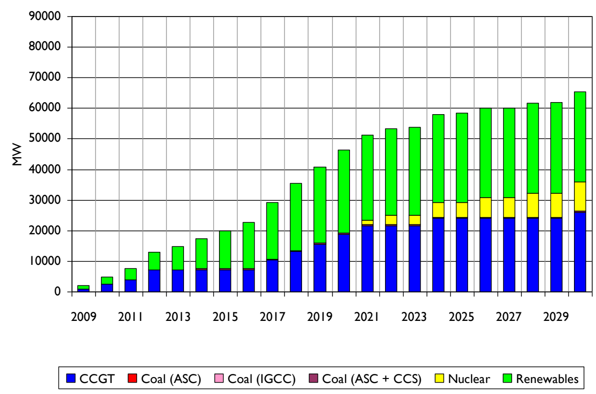


EUA

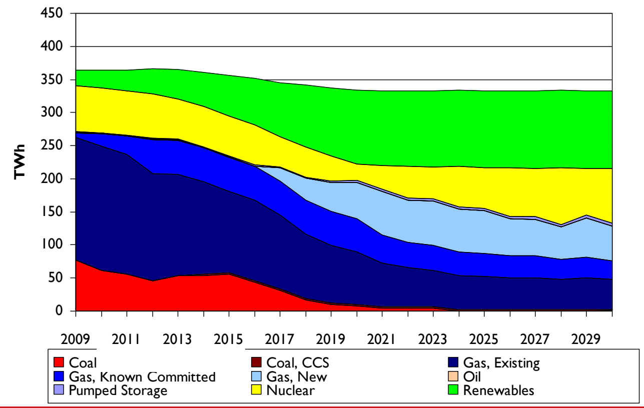


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	27.4	23.2	29.5	29.5
Total nuclear build (GW)	0.0	1.6	9.6	11.2
Total CCGT build (GW)	18.8	11.6	26.0	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	81	117	55	40
CO_2 intensity, g CO_2/kWh (demand)	240	350	160	120
Wholesale costs to consumer, £/MWh	76.1	94.7	97.7	108.0
Spill, GWh	0.01	0.00	0.35	0.35
Energy unserved, GWh	2.0	4.8	0.5	0.4
De-rated capacity margin, average in preceding five years, %	10.2	8.5	9.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

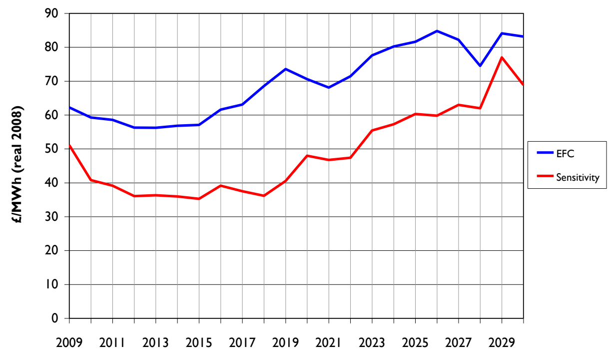
Build profile



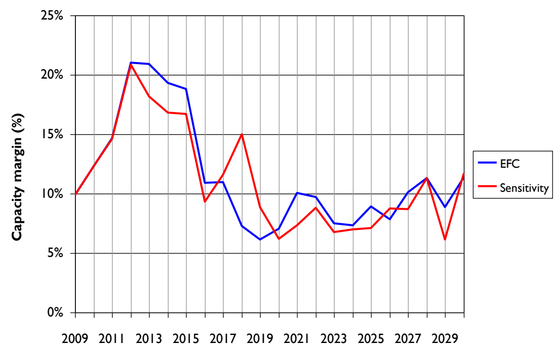
Generation, TWh



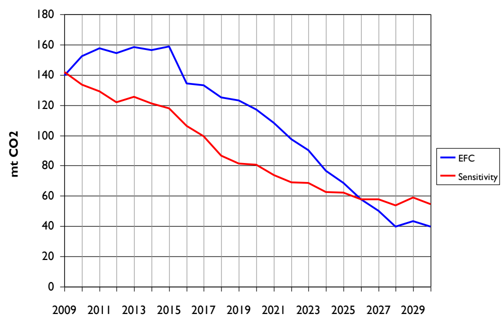
Annual average demand-weighted prices



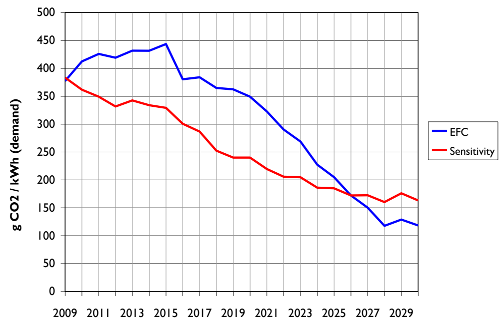
Capacity margin



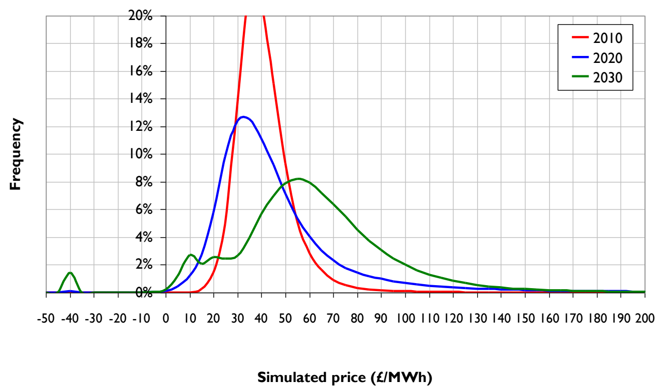
Total CO_2 emissions



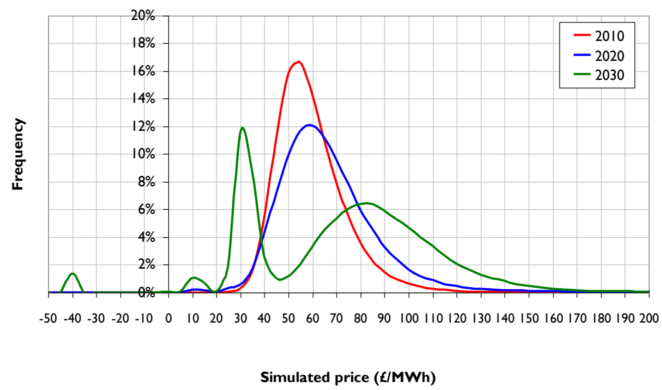
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

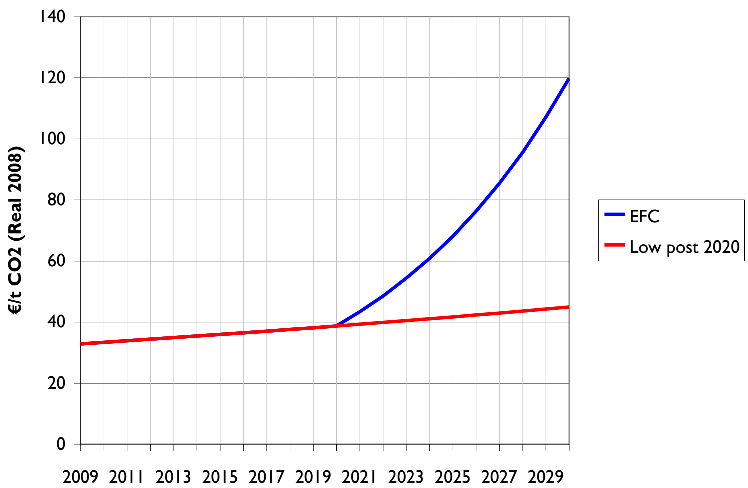


B.11 Low EUA prices post-2020 (11-LE)

The Question: What is the impact of a lower EUA price post-2020?

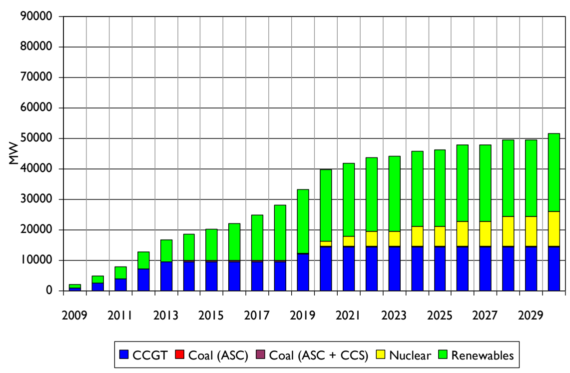
The Assumptions: See graph below.

Figure 54 EUA pricing, EFC scenario and Low

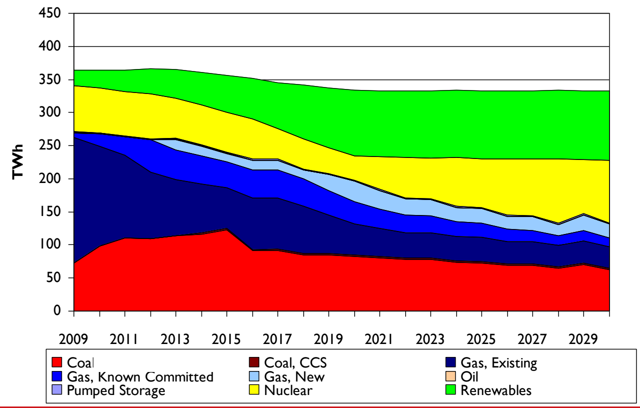


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.4	23.2	25.8	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	14.4	11.6	14.4	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	116	117	86	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	260	120
Wholesale costs to consumer, £/MWh	88.0	94.7	94.8	108.0
Spill, GWh	0.00	0.00	0.13	0.35
Energy unserved, GWh	0.3	4.8	0.9	0.4
De-rated capacity margin, average in preceding five years, %	10.8	8.5	11.6	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

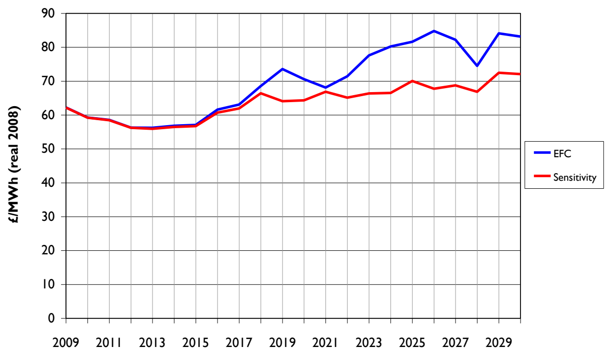
Build profile



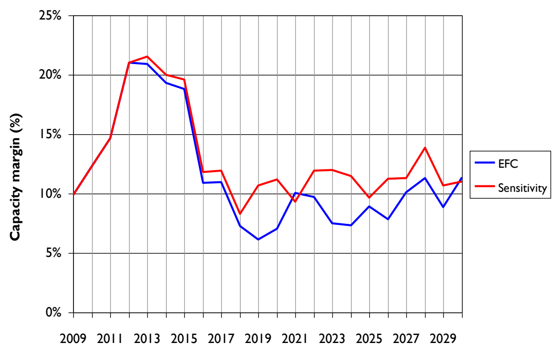
Generation, TWh



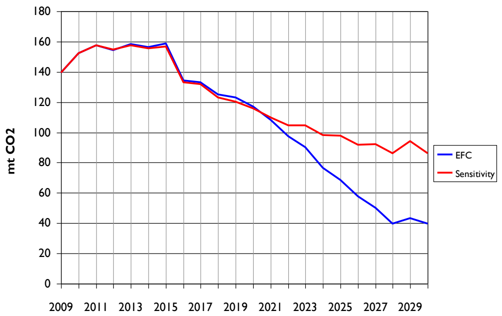
Annual average demand-weighted prices



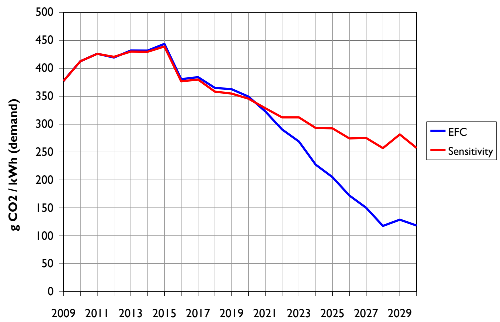
Capacity margin



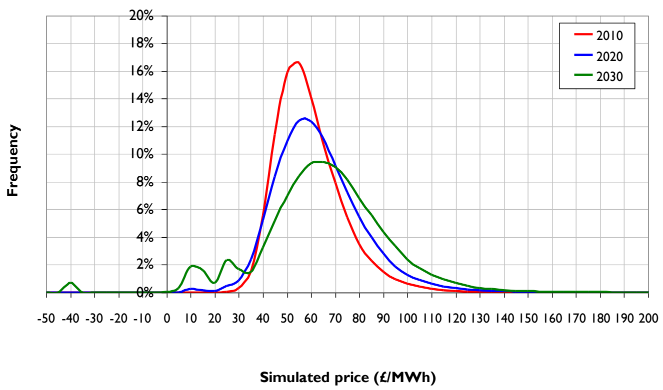
Total CO_2 emissions



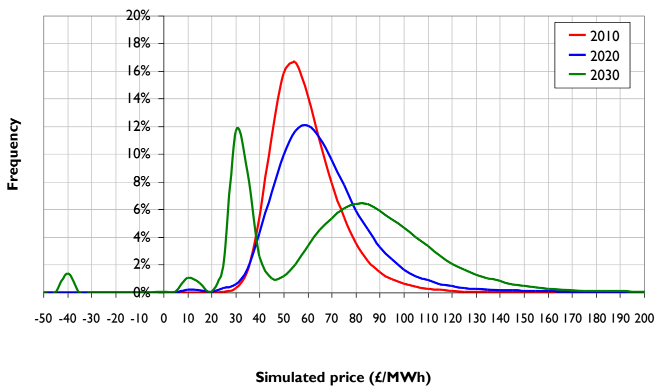
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



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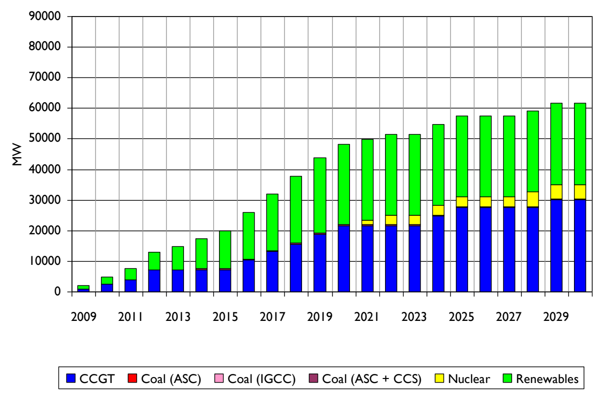
B.12 Low fossil fuel prices and Low EUA prices post 2020 (12-LF-LE)

The Question: What is the combined impact of low commodity prices and low EUA prices post 2020?

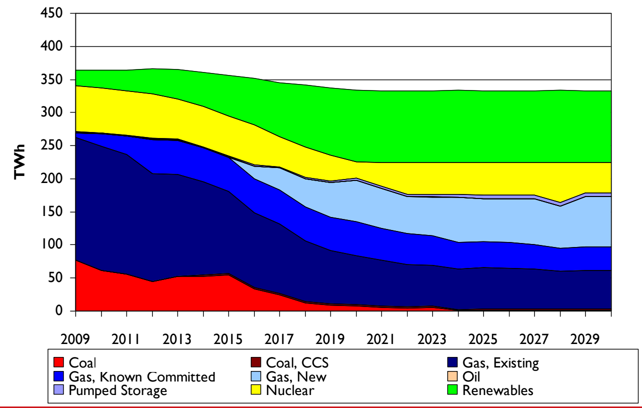
The Assumptions: The oil, gas and coal price from the Lower commodity prices sensitivity (10-LF) and the EUA price from the Low EUA price post 2020 (11-LE) are assumed.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	26.4	23.2	26.5	29.5
Total nuclear build (GW)	0.0	1.6	4.8	11.2
Total CCGT build (GW)	21.6	11.6	30.0	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	81	117	71	40
CO_2 intensity, g CO_2/kWh (demand)	240	350	210	120
Wholesale costs to consumer, £/MWh	66.48	94.67	75.38	108.03
Spill, GWh	0.01	0.00	0.02	0.35
Energy unserved, GWh	0.1	4.8	0.2	0.4
De-rated capacity margin, average in preceding five years, %	11.7	8.5	9.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

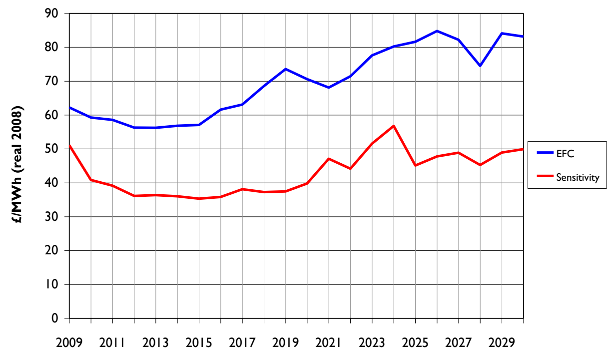
Build profile



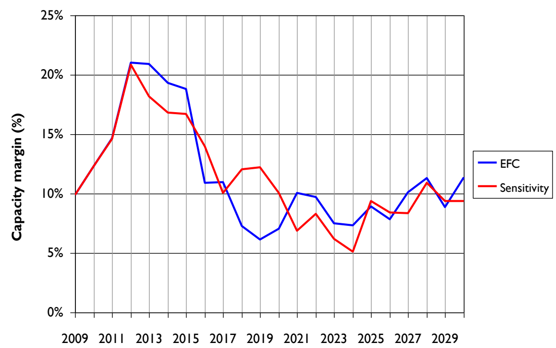
Generation, TWh



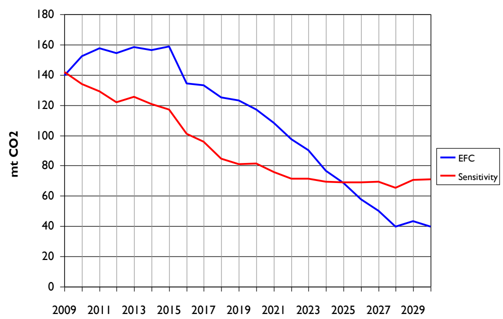
Annual average demand-weighted prices



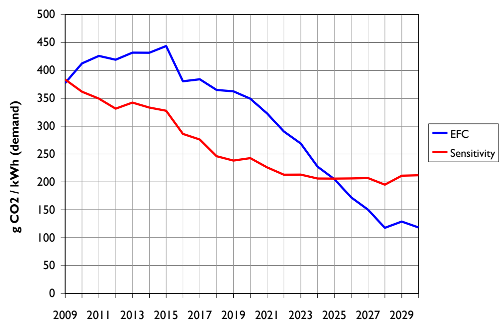
Capacity margin



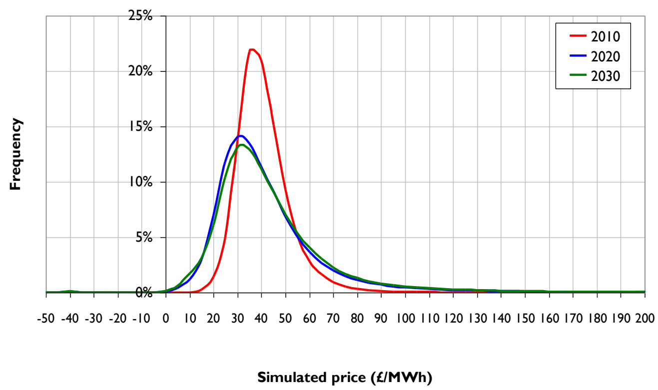
Total CO_2 emissions



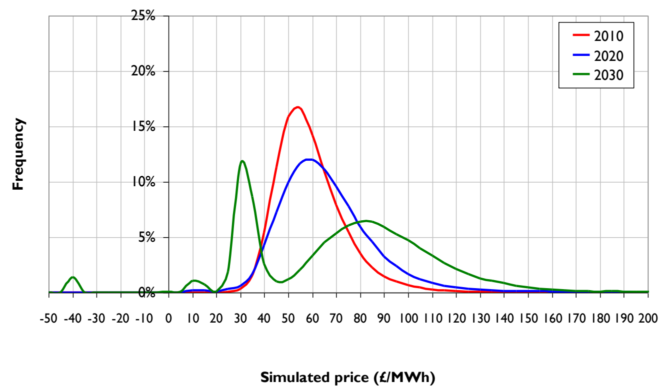
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

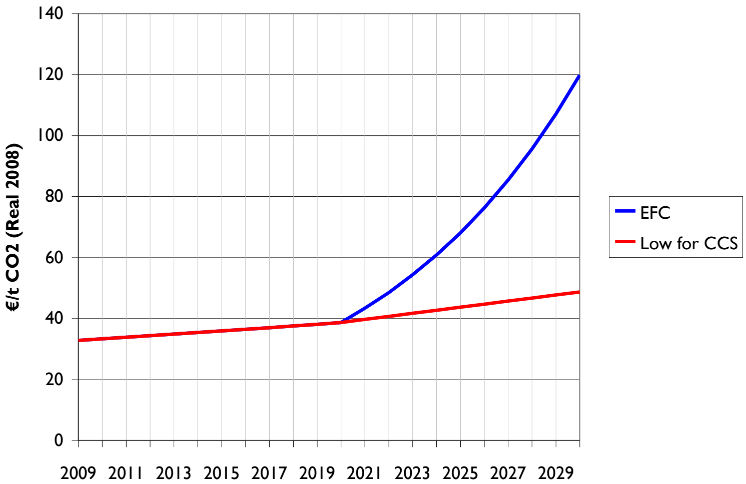


B.13 EUA prices at CCS minimum (13-EC)

The Question: At what EUA price is CCS developed?

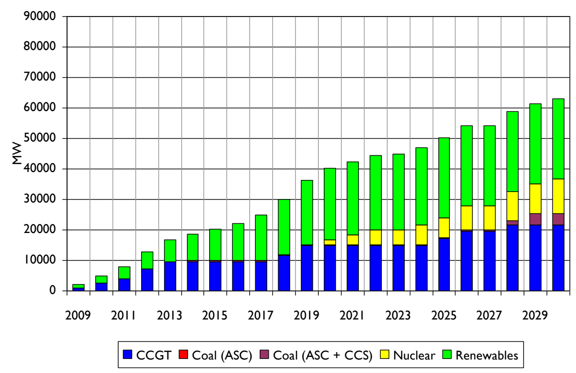
The Assumptions: Starting from the EFC scenario EUA prices are incrementally lowered post-2020 until CCS is commercially commissioned. The EUA prices which achieve this outcome are shown below.

Figure 55 EUA pricing, EFC, Low and CCS breakeven

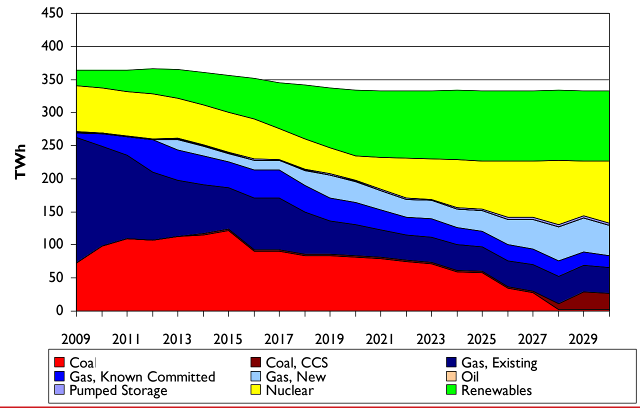


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.4	23.2	26.3	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	14.8	11.6	21.6	19.2
Total CCS build (GW)	0.3	0.3	3.8	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	116	117	47	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	140	120
Wholesale costs to consumer, £/MWh	88.4	94.7	96.6	108.0
Spill, GWh	0.00	0.00	0.17	0.35
Energy unserved, GWh	0.1	4.8	0.4	0.4
De-rated capacity margin, average in preceding five years, %	12.4	8.5	7.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

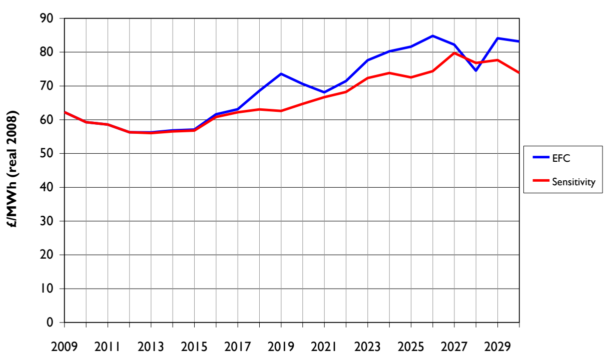
Build profile



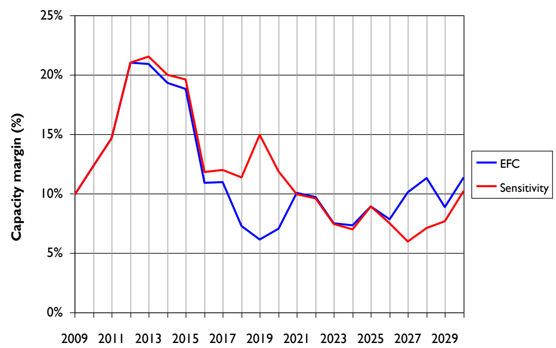
Generation, TWh



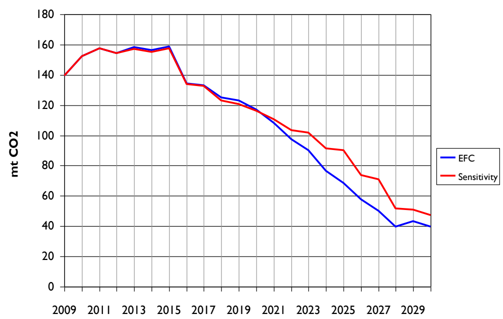
Annual average demand-weighted prices



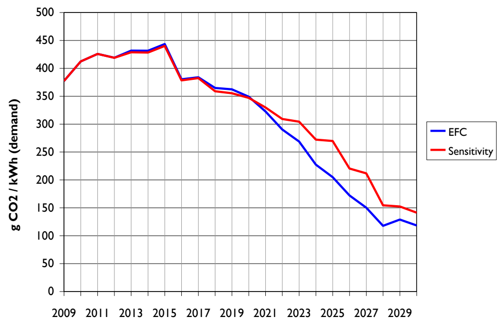
Capacity margin



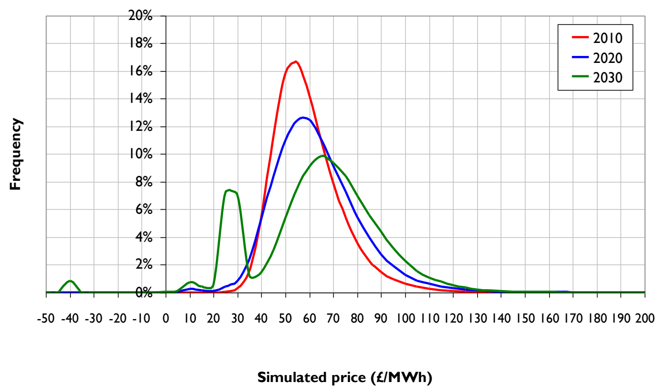
Total CO_2 emissions



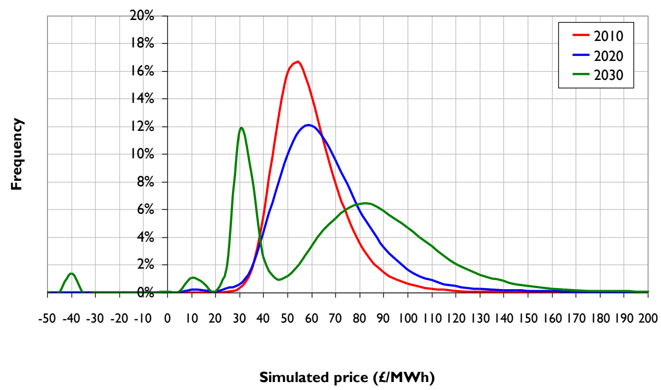
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

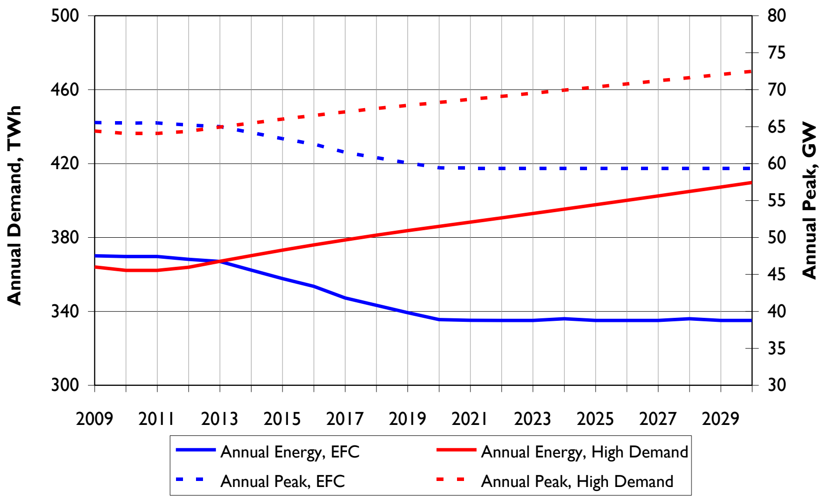


B.14 High Demand (14-HD)

The Question: What happens if demand continues to grow?

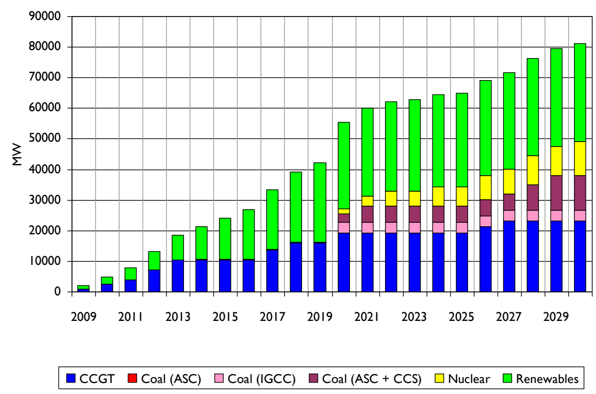
The Assumptions**:** Both annual and peak demand decline slightly in the first few years (given the recession) and then recover in 2011, growing at an annual rate of 0.6 percent per annum by 2020.

Figure 56 Annual and peak demand projections, EFC, High demand

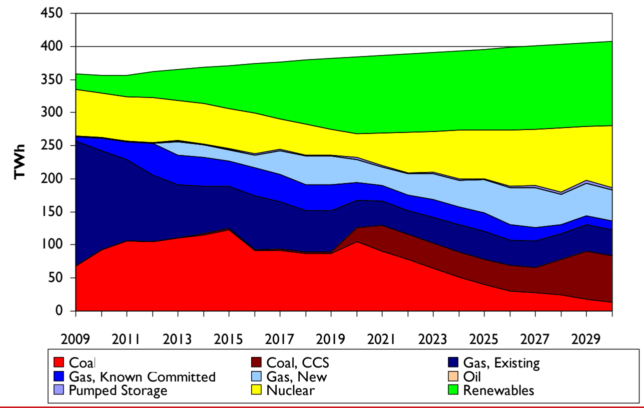


	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	28.4	23.2	32.1	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	19.2	11.6	23.2	19.2
Total CCS build (GW)	2.8	0.3	11.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	130	117	55	40
CO_2 intensity, g CO_2/kWh (demand)	340	350	130	120
Wholesale costs to consumer, £/MWh	87.6	94.67	113.0	108.0
Spill, GWh	0.00	0.00	0.07	0.35
Energy unserved, GWh	0.0	4.8	0.5	0.4
De-rated capacity margin, average in preceding five years, %	10.0	8.5	7.0	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-47,370	

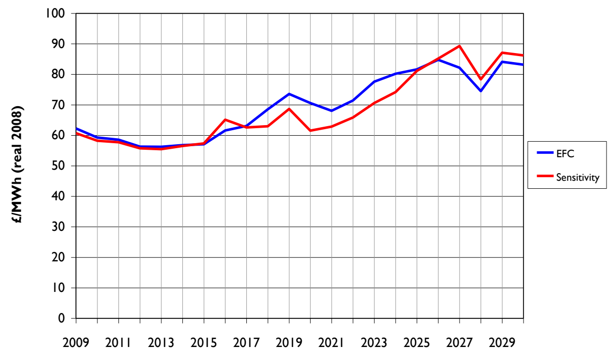
Build profile



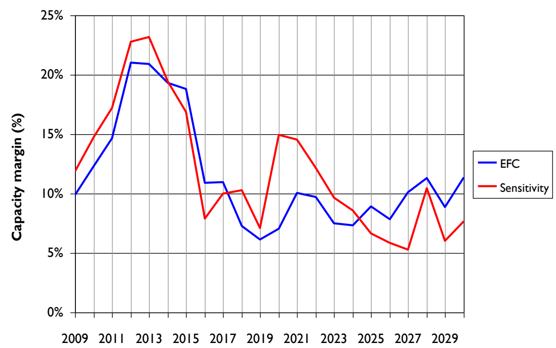
Generation, TWh



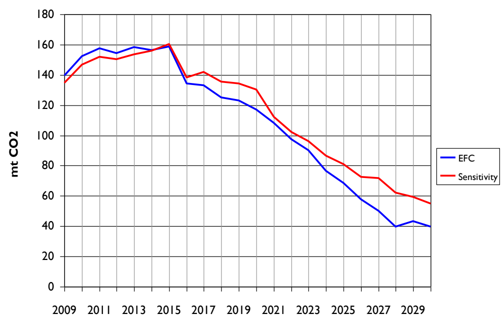
Annual average demand-weighted prices



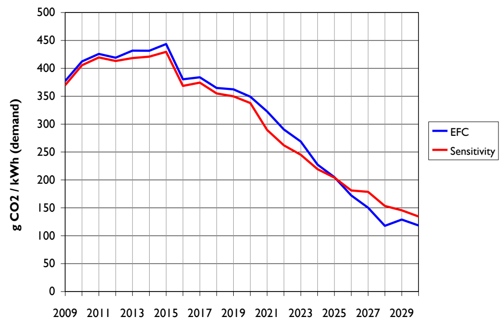
Capacity margin



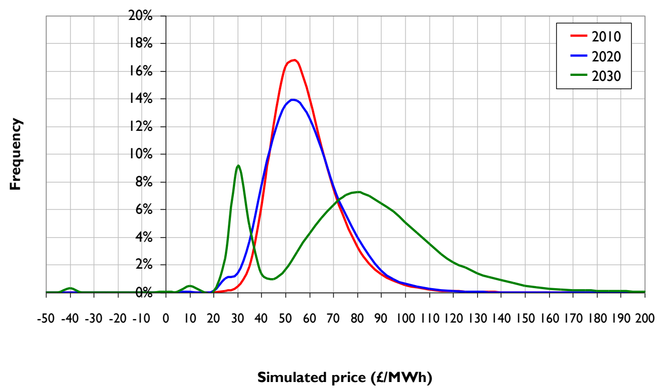
Total CO_2 emissions



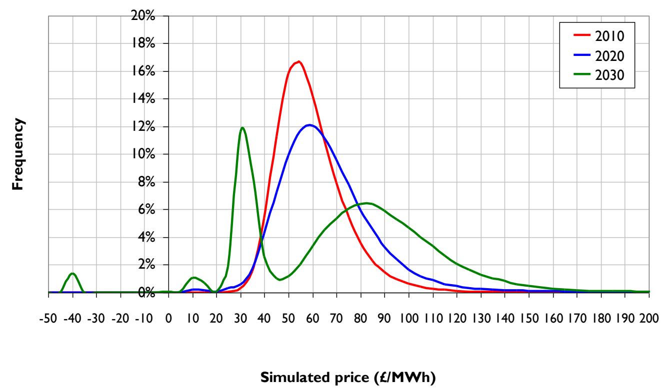
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

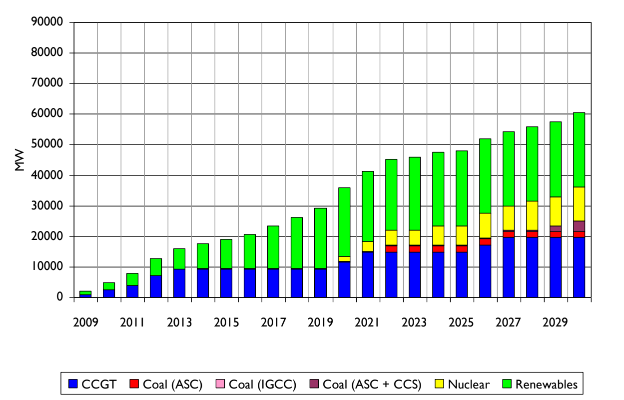
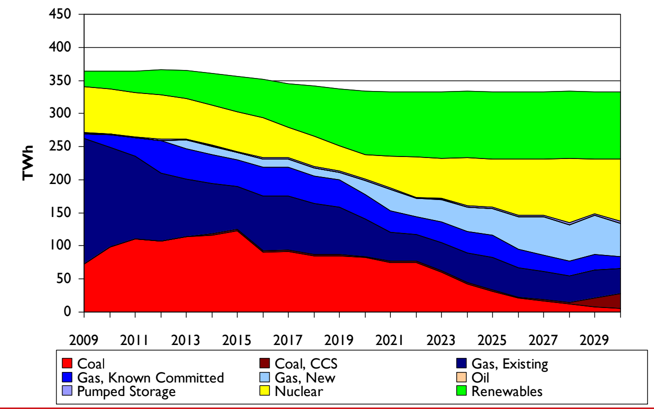
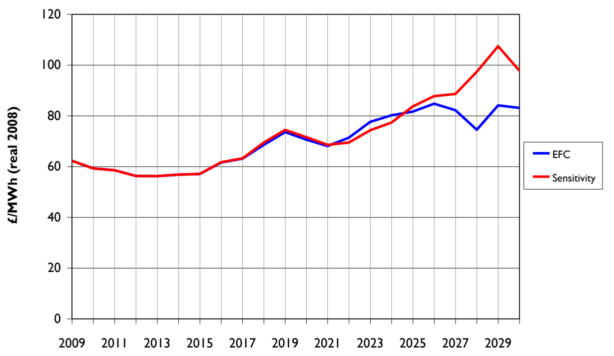
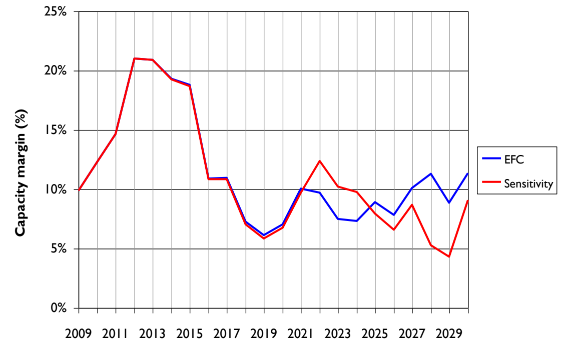
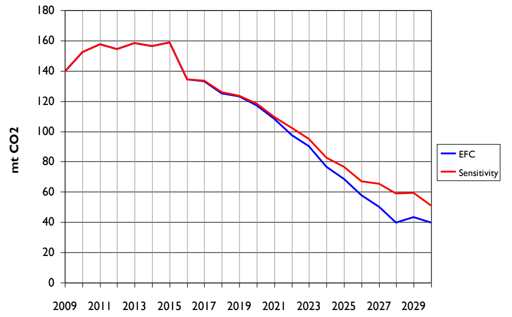
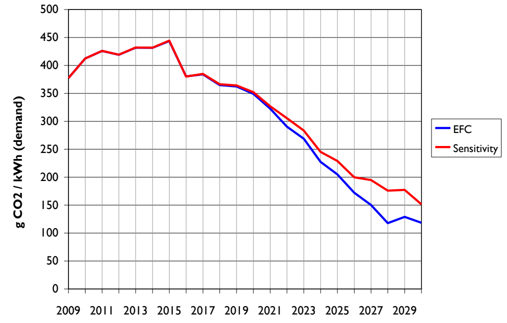
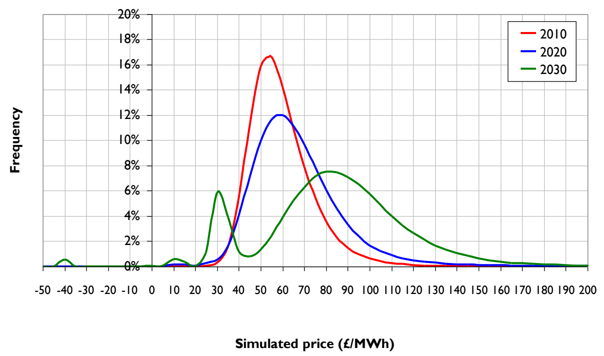
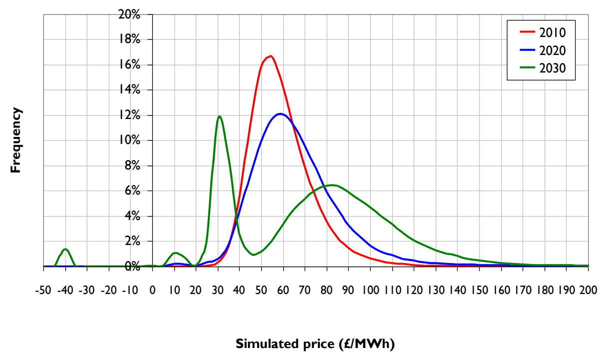


B.15 EUA myopia (15-EM)

The Question: What is the sensitivity in outcomes to the assumption that investors have good visibility of future EUA prices?

The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	22.3	23.2	24.5	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	11.6	11.6	19.6	19.2
Total CCS build (GW)	0.3	0.3	3.3	6.3
Total unabated coal build (GW)	0.0	0.0	2.0	0.0
Total CO_2 emissions, mt CO_2	118	117	51	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	150	120
Wholesale costs to consumer, £/MWh	95.5	94.7	122.5	108.0
Spill, GWh	0.00	0.00	0.09	0.35
Energy unserved, GWh	3.8	4.8	1.2	0.4
De-rated capacity margin, average in preceding five years, %	8.3	8.5	6.8	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			3,823	

Build profile	Generation, TWh
	
Annual average demand-weighted prices	Capacity margin
	
Total CO_2 emissions	Emissions intensity
	
Price duration frequency, sensitivity	Price duration frequency, EFC
	

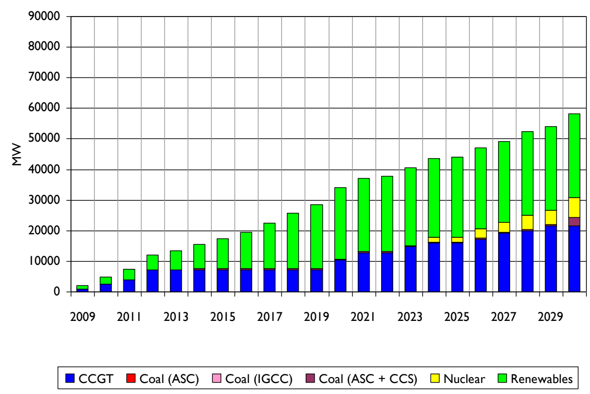
B.16 Higher hurdle rates (16-HH)

The Question: How do investment decisions change when investors perceive the future to be fundamentally more risky?

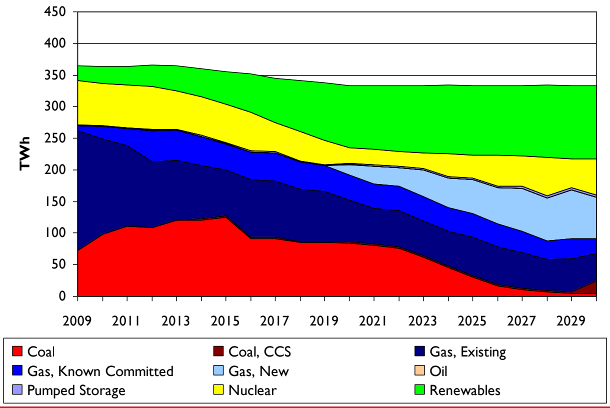
The Assumptions: All hurdle rates are increased by 3 percent relative to with EFC scenario.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.3	23.2	27.4	29.5
Total nuclear build (GW)	0.0	1.6	6.4	11.2
Total CCGT build (GW)	10.4	11.6	21.6	19.2
Total CCS build (GW)	0.3	0.3	2.8	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	122	117	60	40
CO_2 intensity, g CO_2/kWh (demand)	360	350	180	120
Wholesale costs to consumer, £/MWh	126.8	94. 7	137.9	108.0
Spill, GWh	0.00	0.00	0.03	0.35
Energy unserved, GWh	21.1	4.8	0.6	0.4
De-rated capacity margin, average in preceding five years, %	5.7	8.5	6.8	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-14,050	

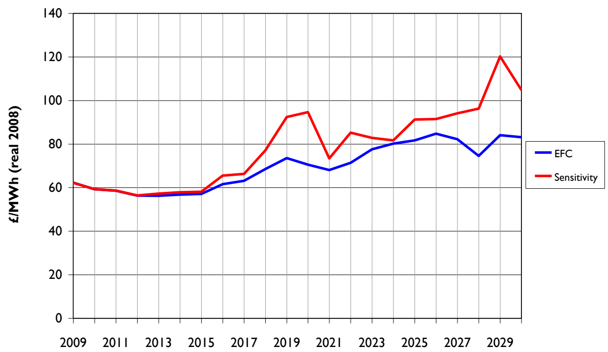
Build profile



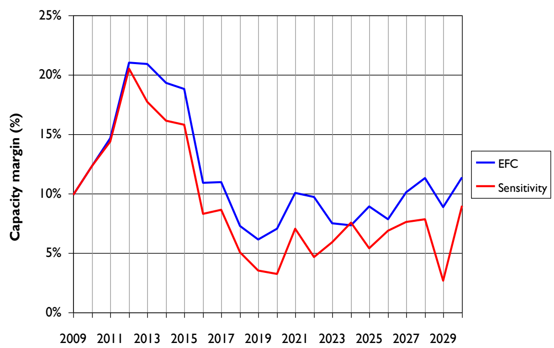
Generation, TWh



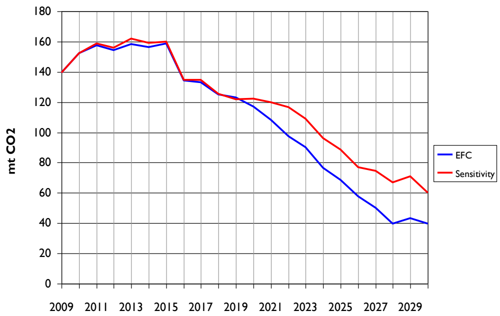
Annual average demand-weighted prices



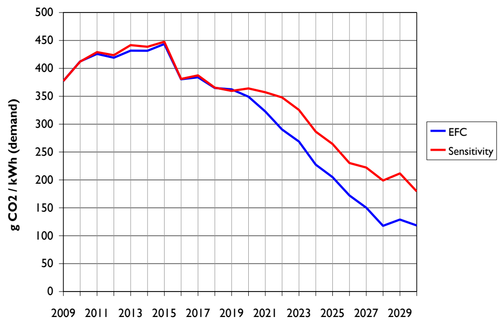
Capacity margin



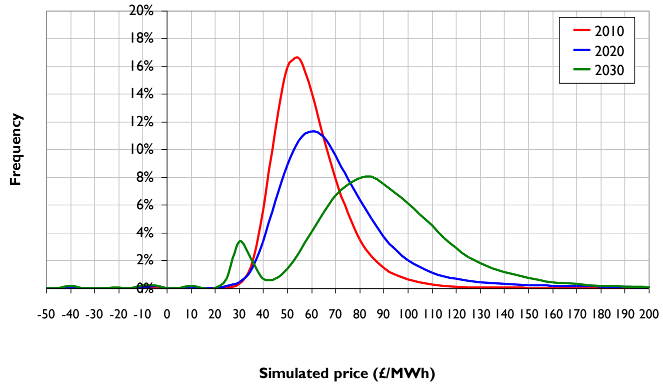
Total CO_2 emissions



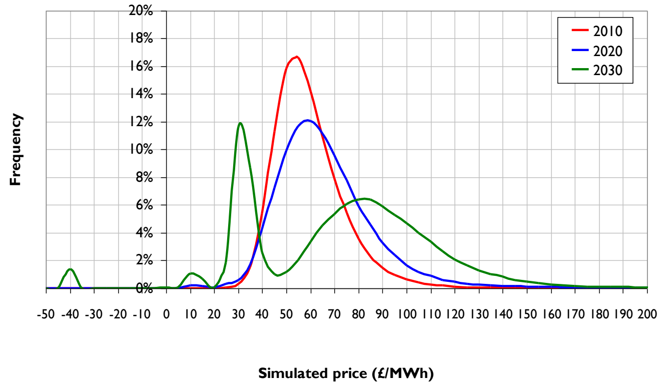
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



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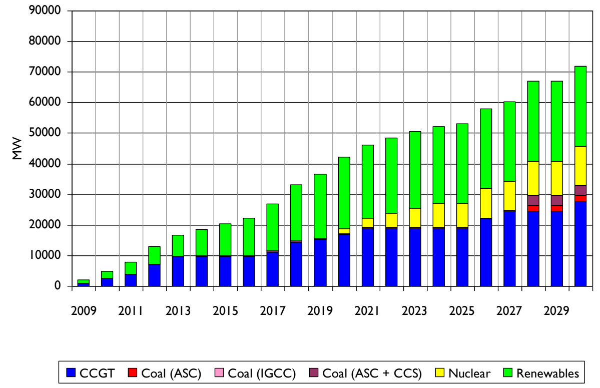
B.17 EUA myopia with Electrification of the heat and transport sector in the peak and offpeak hours (17-EM-EP)

The Question: How will myopia on the EUA price impact in a world in which electrification of the heat and transport sector occurs?

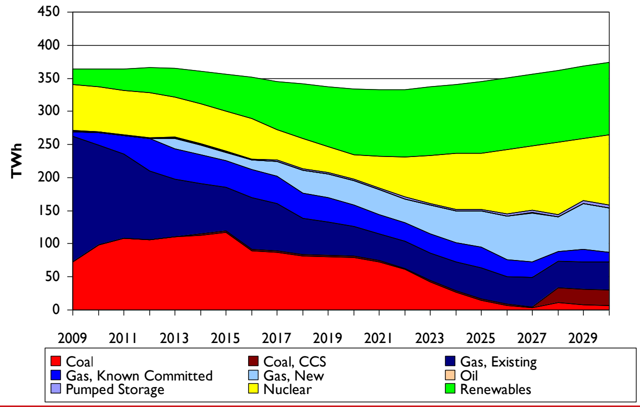
The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over the following ten year period while the demand profile of the electrification of heat and transport sector (falling annual and peak demand through to 2020 and rising annual and peak demand thereafter) is assumed.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.4	23.2	26.1	29.5
Total nuclear build (GW)	1.6	1.6	12.8	11.2
Total CCGT build (GW)	11.6	11.6	19.6	19.2
Total CCS build (GW)	0.3	0.3	3.3	6.3
Total unabated coal build (GW)	0.0	0.0	2.0	0.0
Total CO_2 emissions, mt CO_2	115	117	58.5	40
CO_2 intensity, g CO_2/kWh (demand)	340	350	170	120
Wholesale costs to consumer, £/MWh	88.4	94.7	124.6	108.0
Spill, GWh	0.00	0.00	0.05	0.35
Energy unserved, GWh	0.1	4.8	0.1	0.4
De-rated capacity margin, average in preceding five years, %	10.2	8.5	8.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-7,626	

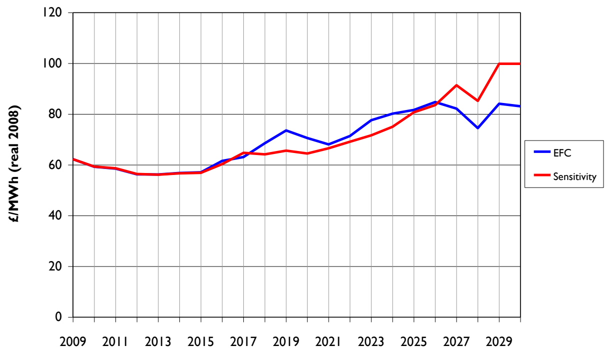
Build profile



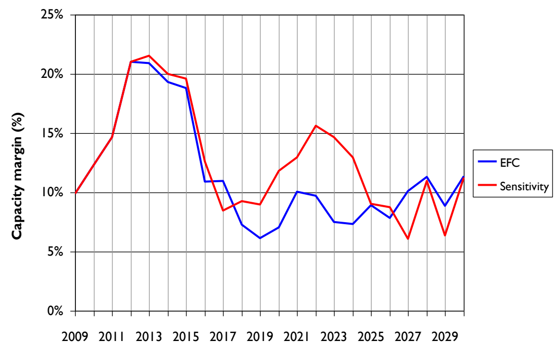
Generation, TWh



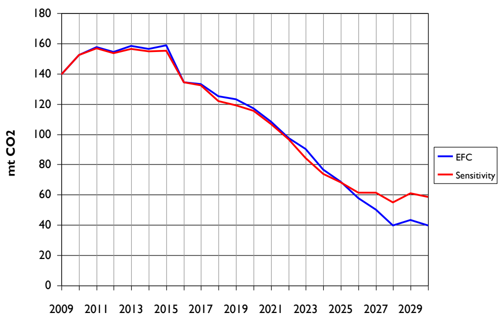
Annual average demand-weighted prices



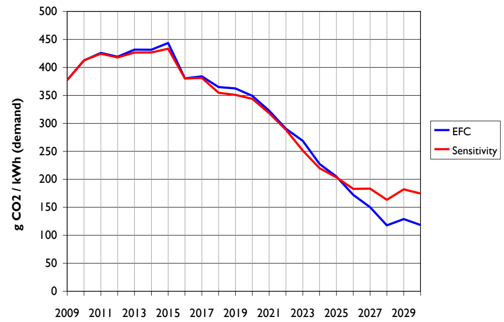
Capacity margin



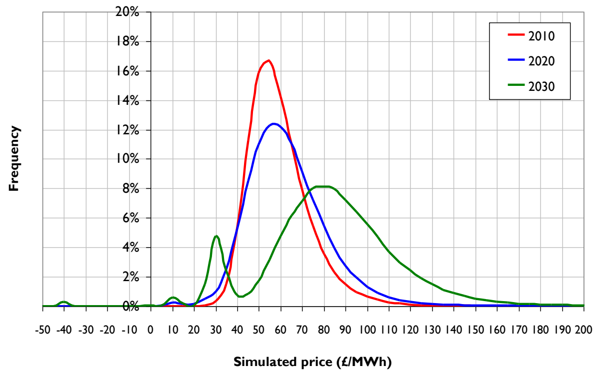
Total CO_2 emissions



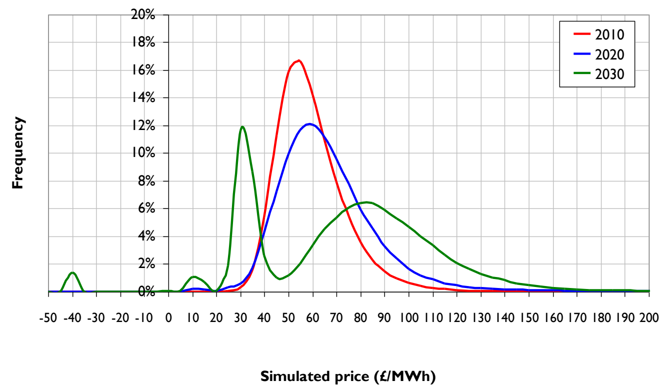
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



REDPOINT

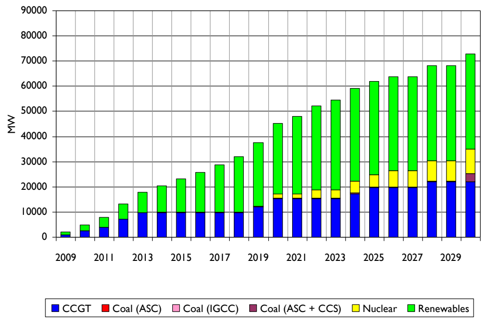
B.18 EUA myopia with High renewable generation (18-EM-HR)

The Question: How will myopia on the EUA price impact in a world in which the Government sets a higher RO target?

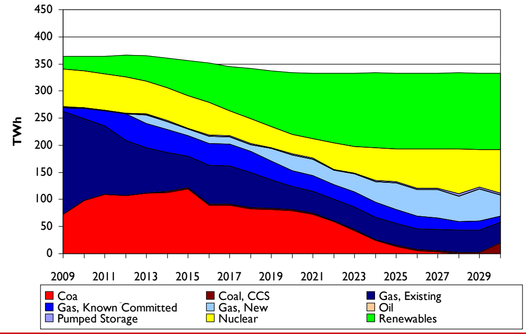
The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period and ROC banding is set so that renewables build achieves the maximum build rate.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	28.1	23.2	37.9	29.5
Total nuclear build (GW)	1.6	1.6	9.6	11.2
Total CCGT build (GW)	15.2	11.6	22.0	19.2
Total CCS build (GW)	0.3	0.3	3.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	110	117	41	40
CO_2 intensity, g CO_2/kWh (demand)	330	350	120	120
Wholesale costs to consumer, £/MWh	94.4	94.7	118.9	108.0
Spill, GWh	0.02	0.00	2.01	0.35
Energy unserved, GWh	0.2	4.8	1.4	0.4
De-rated capacity margin, average in preceding five years, %	12.0	8.5	6.0	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-17,218	

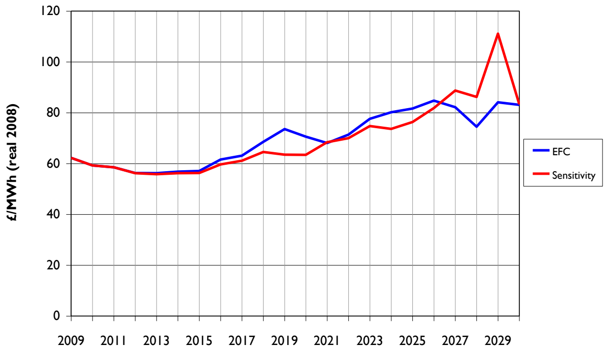
Build profile



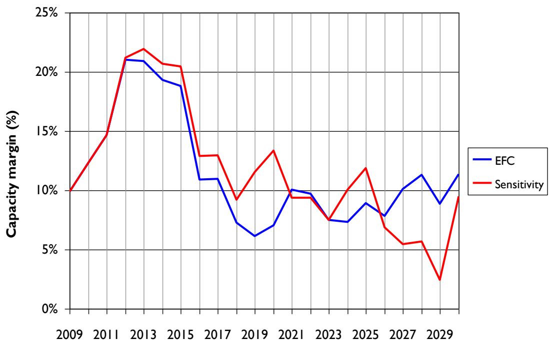
Generation, TWh



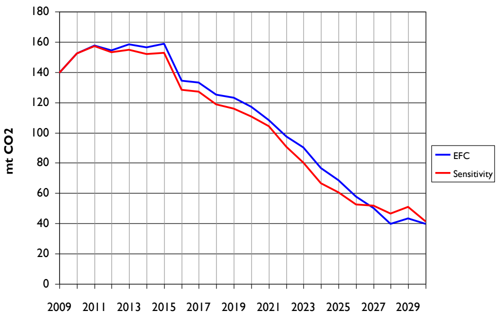
Annual average demand-weighted prices



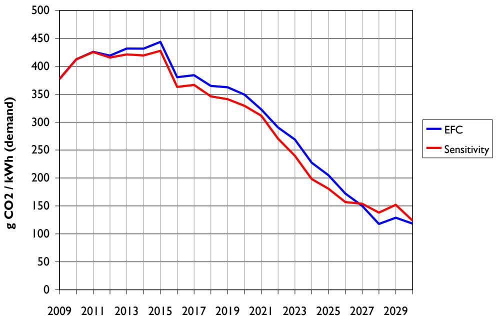
Capacity margin



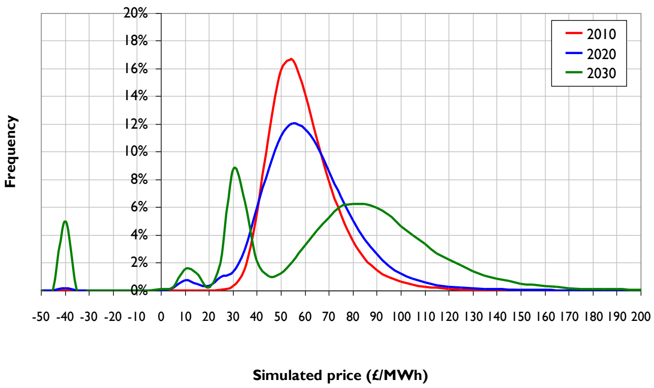
Total CO_2 emissions



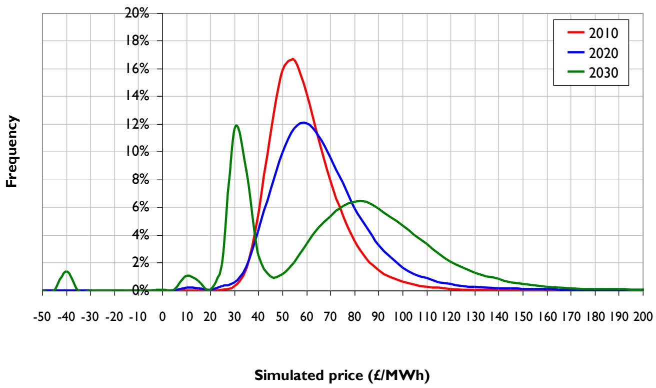
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



REDPOINT

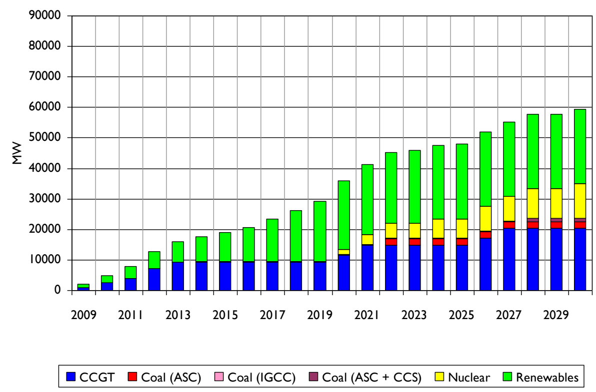
B.19 EUA myopia with Reduced interconnector flexibility (19-EM-LI)

The Question: How will myopia on the EUA price impact in a world in which there is less flexibility to export power to the Continent?

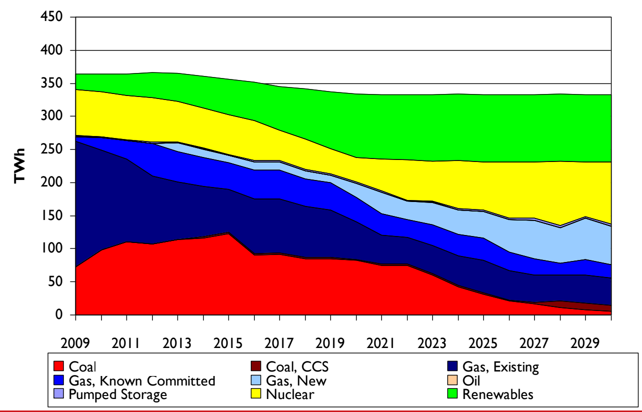
The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period and the maximum expected export capacity is reduced to 1 GW from 3.3 GW.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	22.3	23.2	24.5	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	11.6	11.6	20.4	19.2
Total CCS build (GW)	0.3	0.3	1.3	6.3
Total unabated coal build (GW)	0.0	0.0	2.0	0.0
Total CO_2 emissions, mt CO_2	118	117	56	40
CO_2 intensity, g CO_2/kWh (demand)	350	350	170	120
Wholesale costs to consumer, £/MWh	95.42	94.67	125.35	108.03
Spill, GWh	0.00	0.00	0.24	0.35
Energy unserved, GWh	3.8	4.8	2.5	0.4
De-rated capacity margin, average in preceding five years, %	8.3	8.5	7.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			3,690	

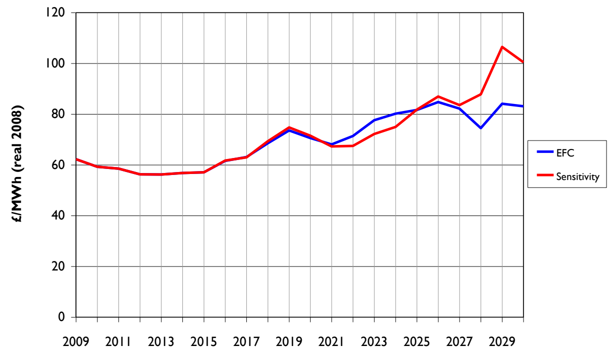
Build profile



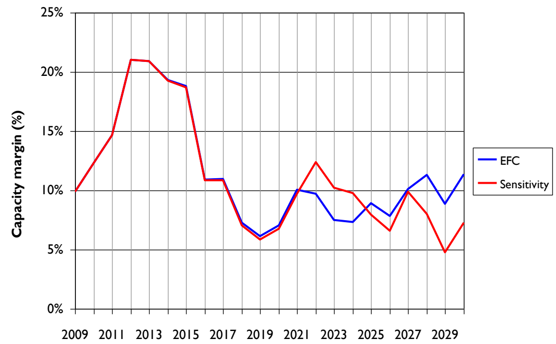
Generation, TWh



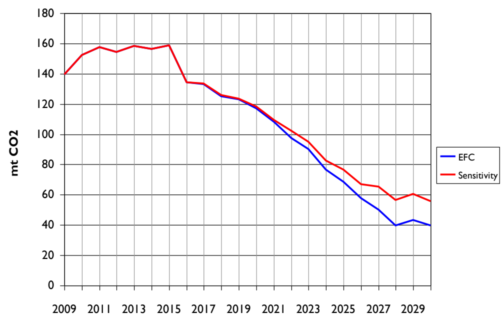
Annual average demand-weighted prices



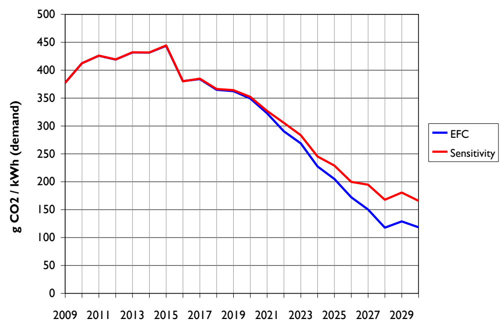
Capacity margin



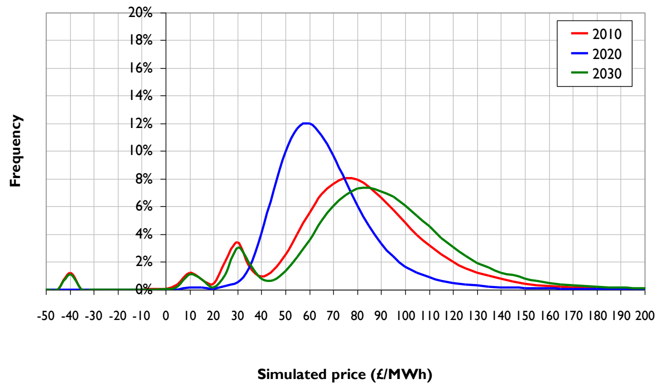
Total CO_2 emissions



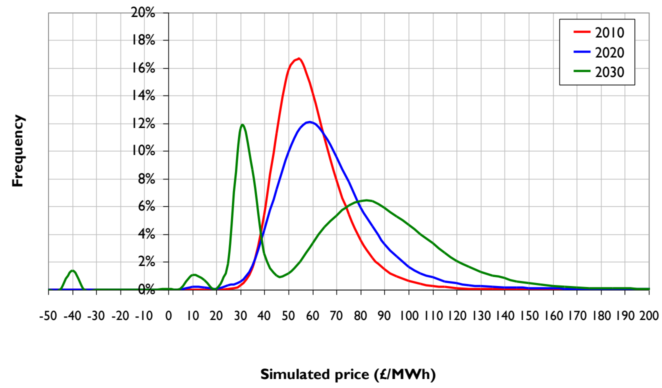
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



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B.20 EUA myopia with Higher hurdle rates (20-EM-HH)

The Question: How will myopia on the EUA price impact in a riskier investment environment?

The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period and hurdle rates are increased by 3 percent relative to the EFC sensitivity across all technologies for all companies and for all years.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.5	23.2	27.2	29.5
Total nuclear build (GW)	0.0	1.6	4.8	11.2
Total CCGT build (GW)	10.4	11.6	20.0	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	3.0	0.0
Total CO_2 emissions, mt CO_2	122	117	75	40
CO_2 intensity, g CO_2/kWh (demand)	360	350	220	120
Wholesale costs to consumer, £/MWh	126.1	94.7	152.1	108.0
Spill, GWh	0.00	0.00	0.01	0.35
Energy unserved, GWh	21.0	4.8	7.9	0.4
De-rated capacity margin, average in preceding five years, %	5.9	8.5	2.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-13,251	

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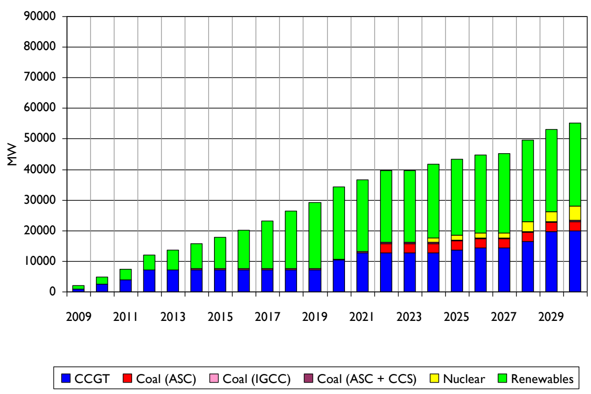
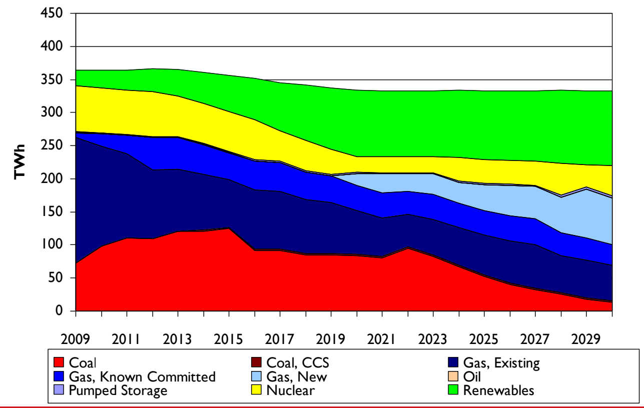
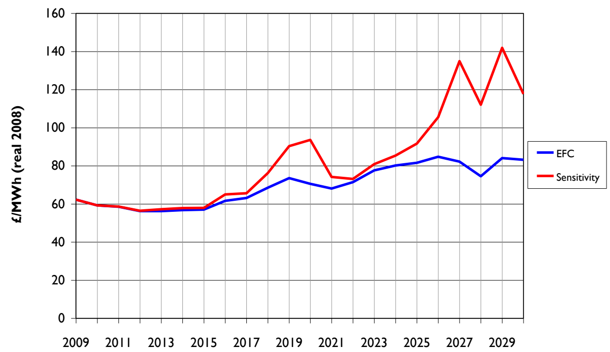
Build profile



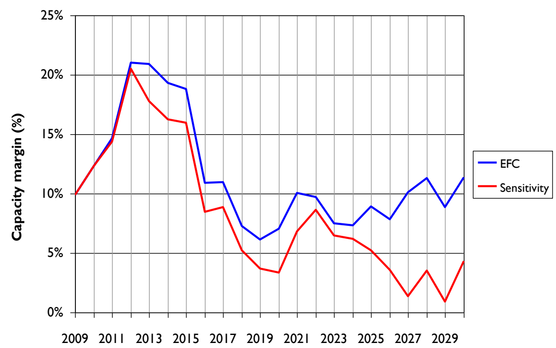
Generation, TWh



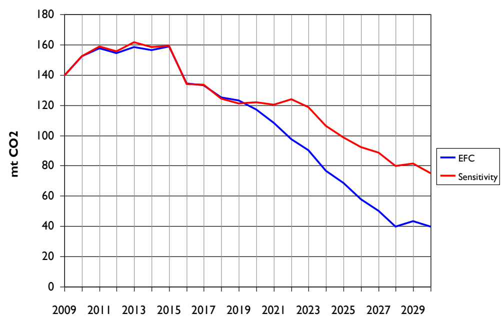
Annual average demand-weighted prices



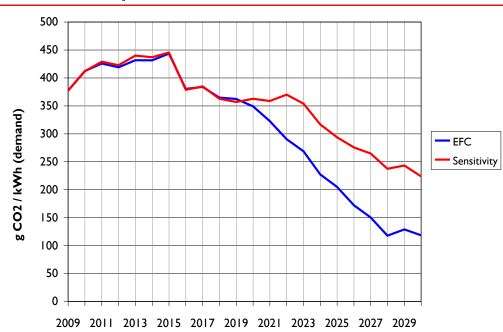
Capacity margin



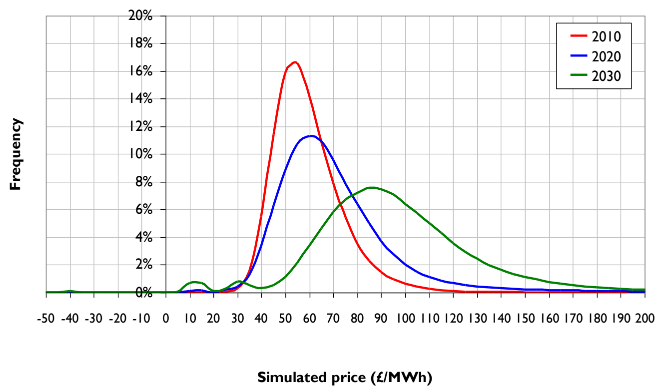
Total CO_2 emissions



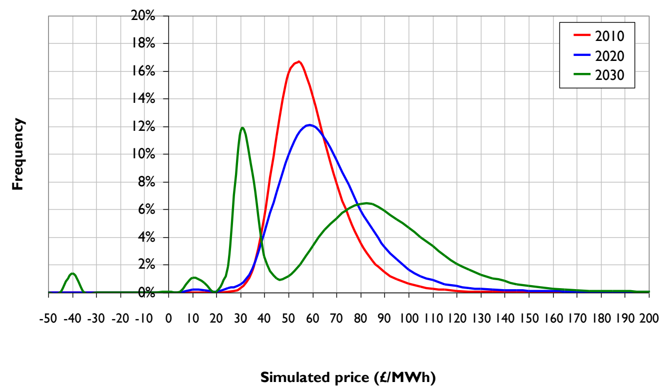
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



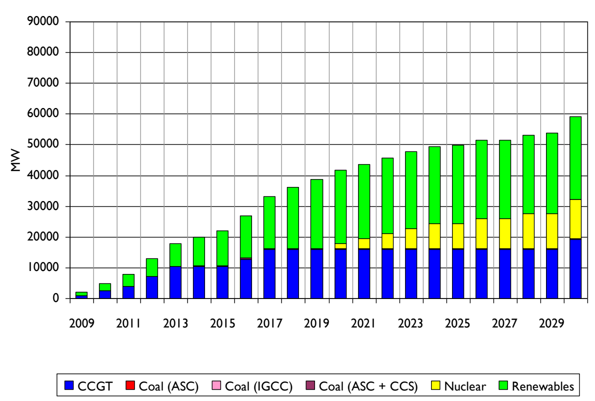
B.21 EUA myopia, Demand myopia, Electrification of the heat and transport sector in the peak and offpeak hours (21-EM-DM-EP)

The Question: How will myopia on the EUA price impact in a world in which electrification of the heat and transport sector occurs, but investors have no expectation of future demand changes?

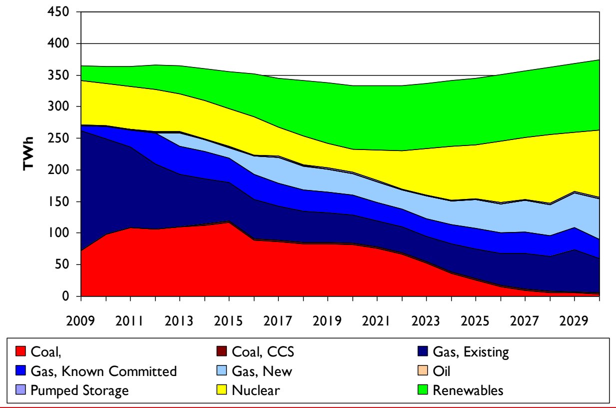
The Assumptions: Investment decisions are based on the prevailing EUA price and demand level in the year the decision to commit is made, with the EUA prices being as in the EFC scenario and demand as in the transport and heat electrification sensitivity.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.8	23.2	26.8	29.5
Total nuclear build (GW)	1.6	1.6	12.8	11.2
Total CCGT build (GW)	16.0	11.6	19.2	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	115	117	66	40
CO_2 intensity, g CO_2/kWh (demand)	340	350	170	120
Wholesale costs to consumer, £/MWh	88.5	94.7	197.2	108.0
Spill, GWh	0.00	0.00	0.05	0.35
Energy unserved, GWh	0.2	4.8	103.5	0.4
De-rated capacity margin, average in preceding five years, %	16.2	8.5	1.6	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-7,010	

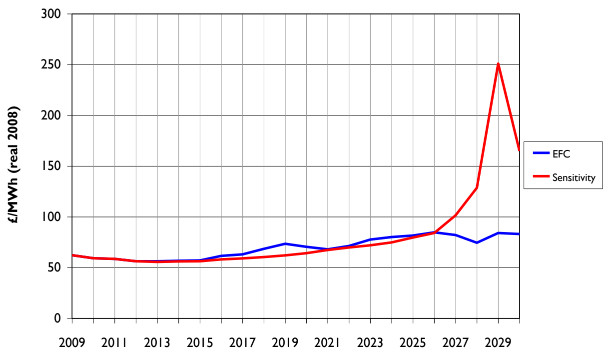
Build profile



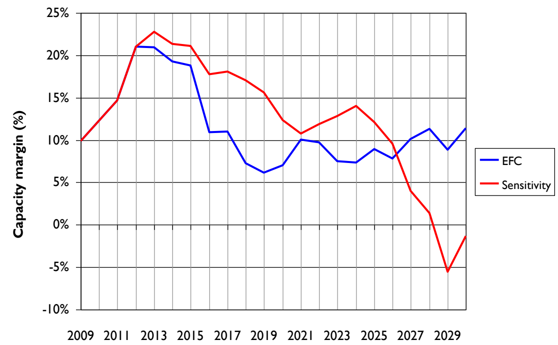
Generation, TWh



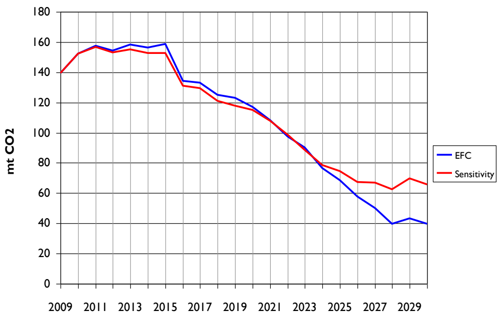
Annual average demand-weighted prices



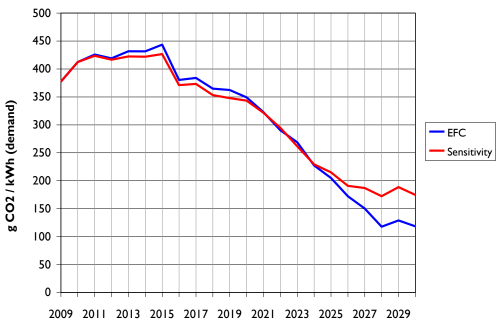
Capacity margin



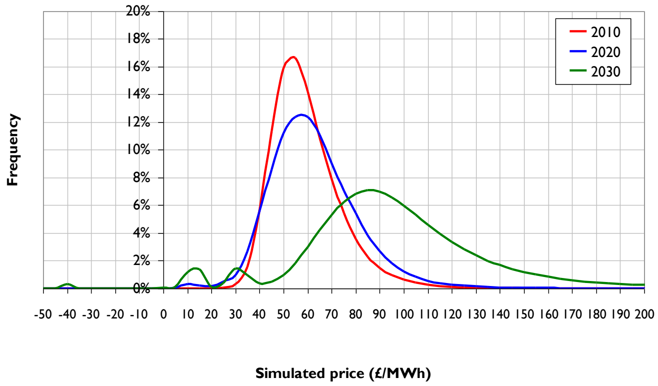
Total CO_2 emissions



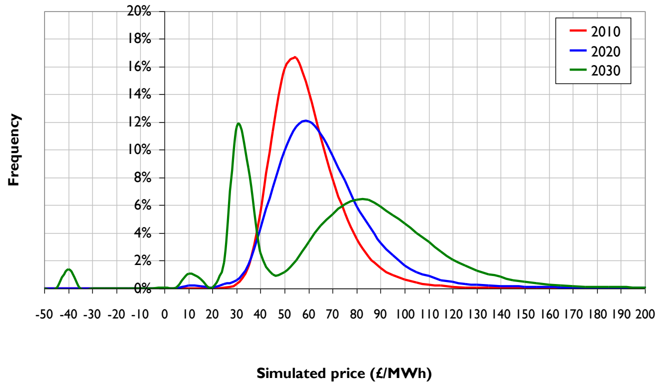
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



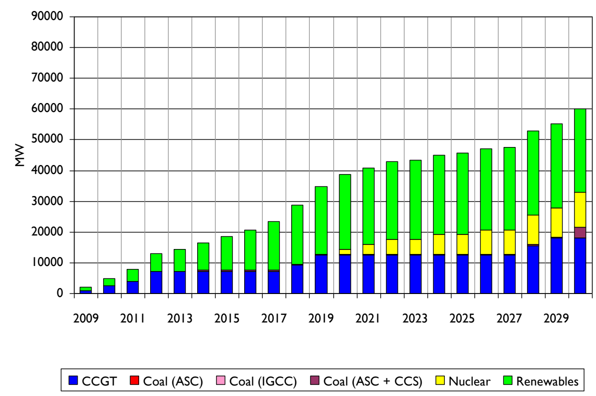
B.22 EUA myopia with outturn price expectation (22-EM-PM)

The Question: What is the impact of investors not only lacking visibility on the EUA price, but limited visibility on forward power prices?

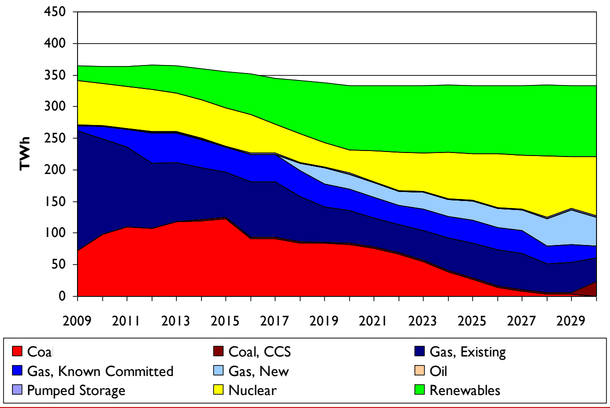
The Assumptions: Investors' expectation of future prices are based more on outturn spot prices than future expected prices.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	24.3	23.2	27.3	29.5
Total nuclear build (GW)	1.6	1.6	11.2	11.2
Total CCGT build (GW)	12.4	11.6	18.0	19.2
Total CCS build (GW)	0.3	0.3	3.6	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	115	117	46	40
CO_2 intensity, g CO_2/kWh (demand)	340	350	140	120
Wholesale costs to consumer, £/MWh	88.7	94.7	122.9	108.0
Spill, GWh	0.00	0.00	0.22	0.35
Energy unserved, GWh	0.1	4.8	6.6	0.4
De-rated capacity margin, average in preceding five years, %	10.3	8.5	5.3	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			778	

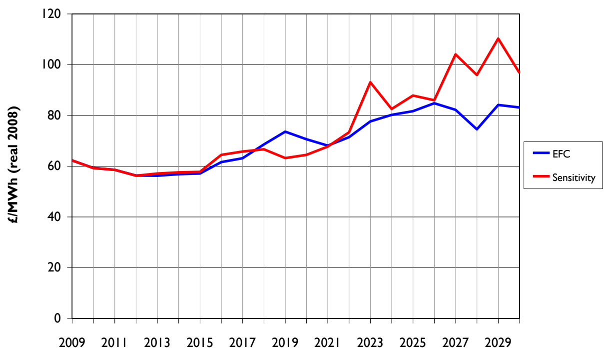
Build profile



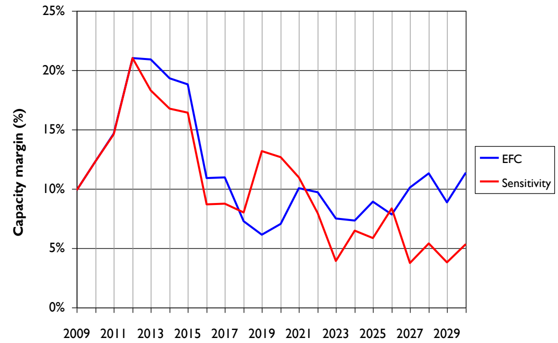
Generation, TWh



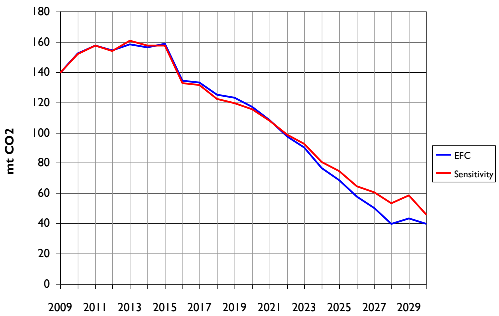
Annual average demand-weighted prices



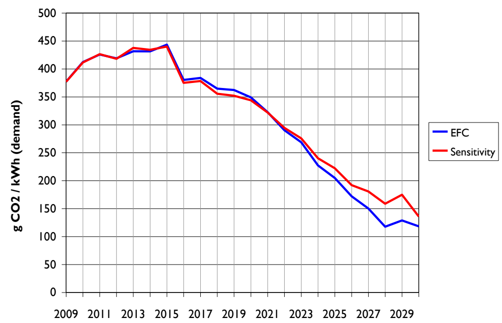
Capacity margin



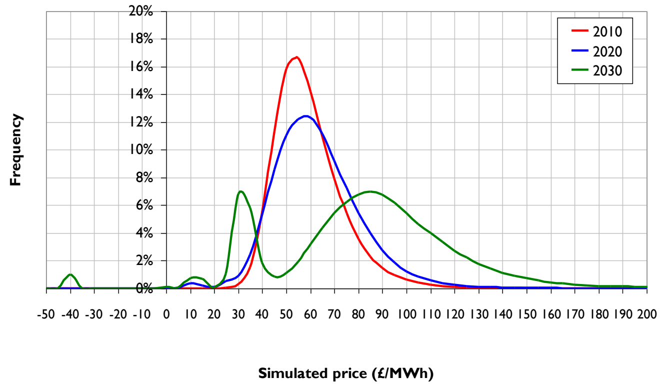
Total CO_2 emissions



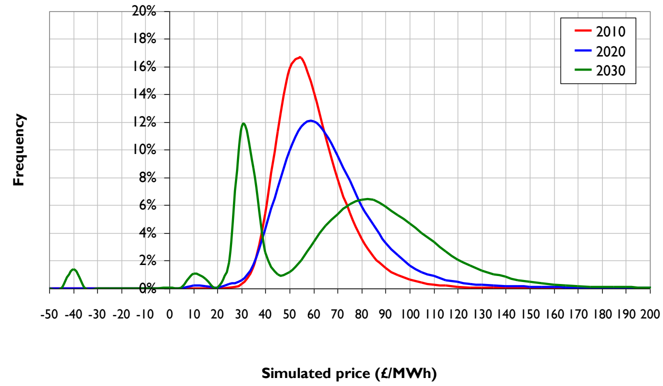
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



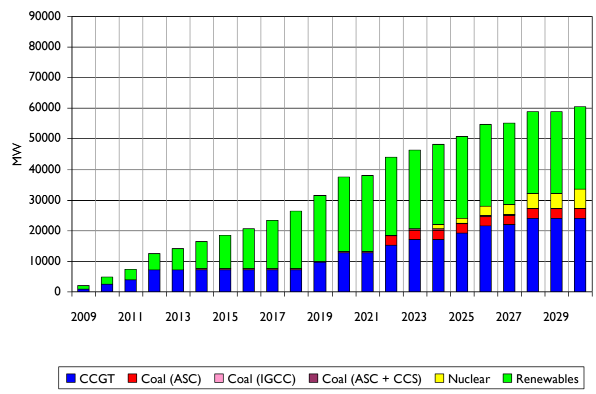
B.23 EUA myopia with Higher hurdle rates and Low interconnector flexibility (23-EM-HH-LI)

The Question: What decisions will be made by investors who are not only myopic on the EUA price and perceive the future to be fundamentally riskier, but who can rely less on the interconnector to absorb excess energy given increased correlation of intermittent generation with that on the Continent?

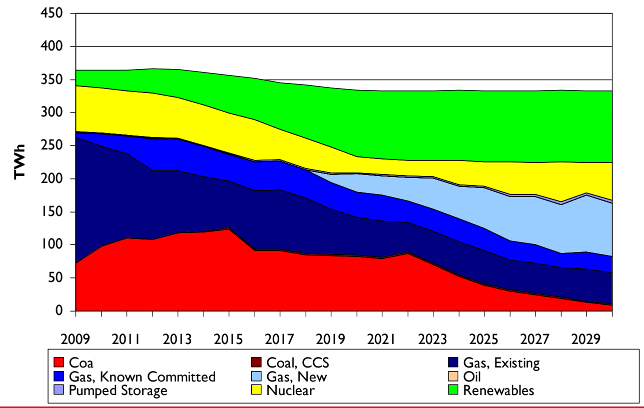
The Assumptions: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period, hurdle rates are increased by 3 percent relative to with EFC across all technologies for all companies and for all years, and the maximum expected export capacity is reduced to 1.0 GW from 3.3 GW.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	24.4	23.2	26.7	29.5
Total nuclear build (GW)	0.0	1.6	6.4	11.2
Total CCGT build (GW)	12.8	11.6	24.0	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	3.0	0.0
Total CO_2 emissions, mt CO_2	121	117	70	40
CO_2 intensity, g CO_2/kWh (demand)	360	350	210	120
Wholesale costs to consumer, £/MWh	105.3	94.7	143.7	108.0
Spill, GWh	0.00	0.00	0.05	0.35
Energy unserved, GWh	8.1	4.8	3.6	0.4
De-rated capacity margin, average in preceding five years, %	6.3	8.5	5.5	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-24,679	

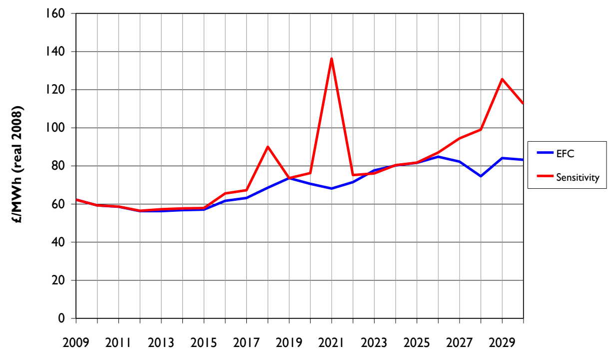
Build profile



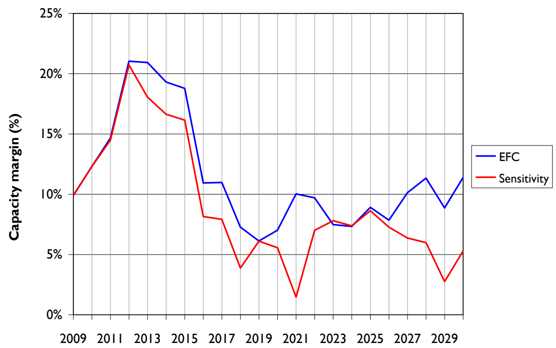
Generation, TWh



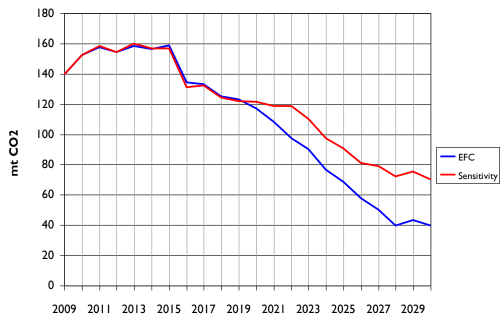
Annual average demand-weighted prices



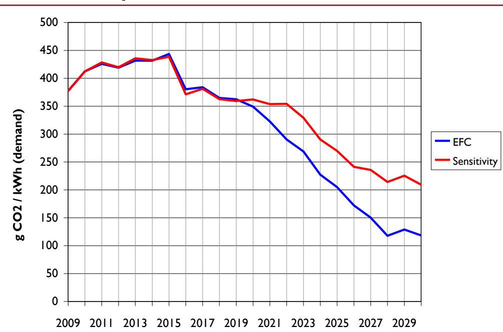
Capacity margin



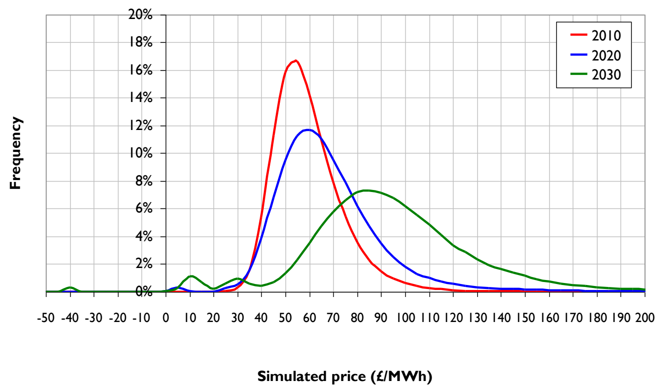
Total CO_2 emissions



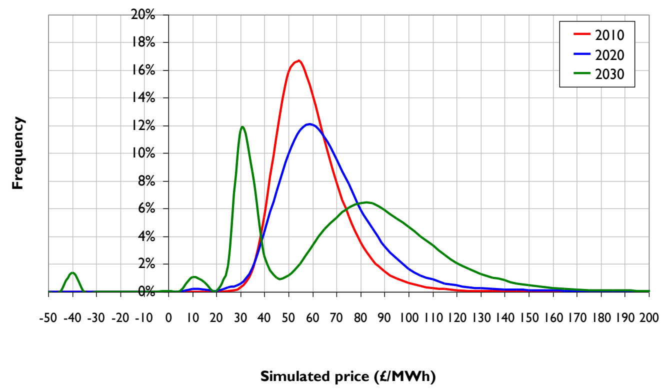
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



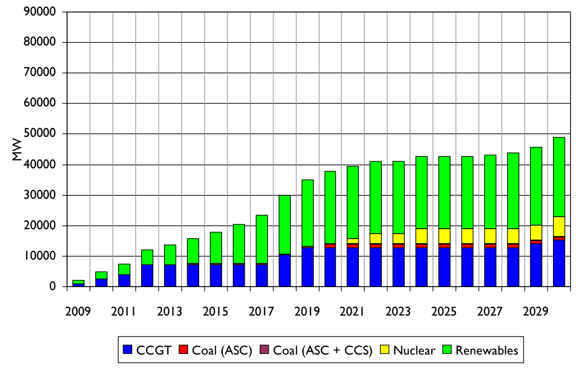
B.24 EUA myopia with Higher hurdle rates and Peak prices dampened (24-EM-HH-PP)

<u>The Question</u>: What is the impact of myopia on the EUA price, a future perceived to be fundamentally more risky, and a market which does not reflect scarcity value?

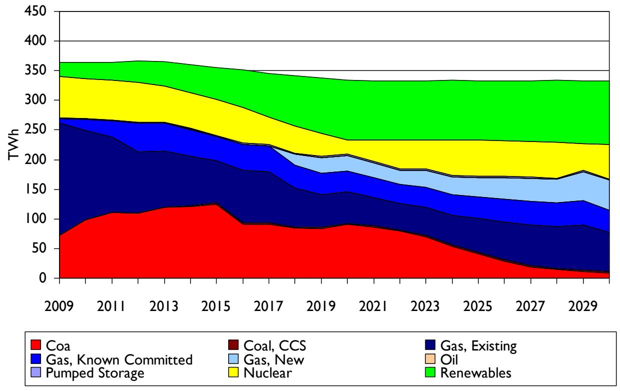
<u>The Assumptions</u>: Investment decisions are based on the EUA price in the year the decision to commit is made rather than on expected EUA prices over following ten year period, hurdle rates are increased by 3 percent relative to EFC across all technologies for all companies and for all years, and prices are prevented from peaking above 500 £/MWh.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	23.6	23.2	26.1	29.5
Total nuclear build (GW)	0.0	1.6	6.4	11.2
Total CCGT build (GW)	12.8	11.6	15.2	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	1.0	0.0	1.0	0.0
Total CO_2 emissions, mt CO_2	121	117	72	40
CO_2 intensity, g CO_2/kWh (demand)	370	350	220	120
Wholesale costs to consumer, £/MWh	94.4	94.7	142.6	108.0
Spill, GWh	0.00	0.00	0.02	0.35
Energy unserved, GWh	0.2	4.8	10.3	0.4
De-rated capacity margin, average in preceding five years, %	10.6	8.5	4.7	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			-13,510	

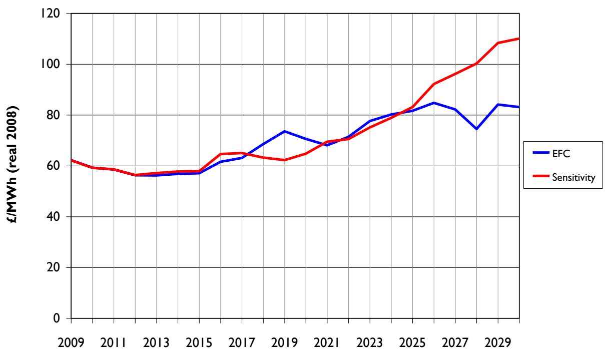
Build profile



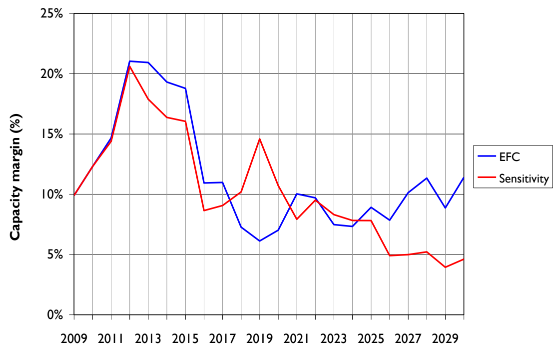
Generation, TWh



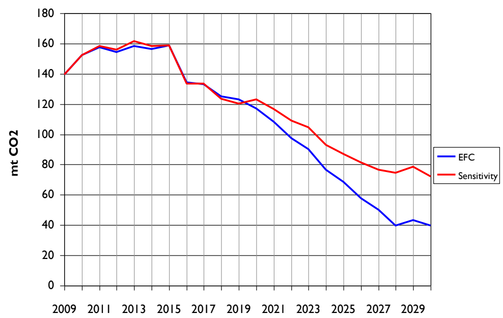
Annual average demand-weighted prices



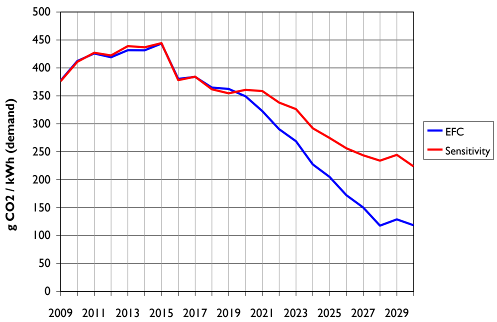
Capacity margin



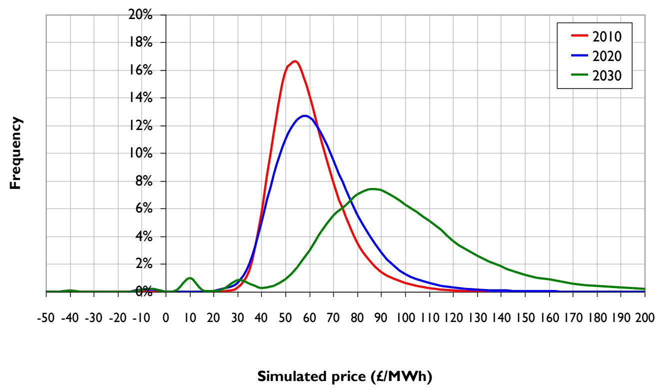
Total CO_2 emissions



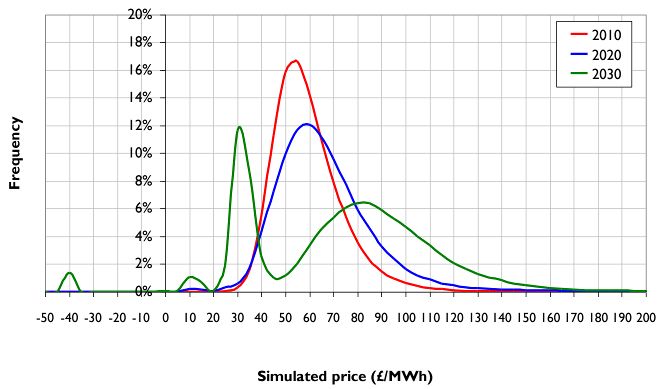
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC



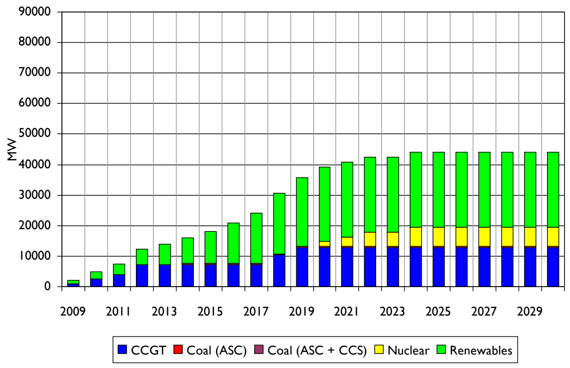
B.25 Higher hurdle rates and Low EUA prices post 2020 (25-HH-LE)

The Question: To what extent is decarbonisation limited by lower EUA prices post-2020 and in a world in which investors perceive the future to be fundamentally more risky?

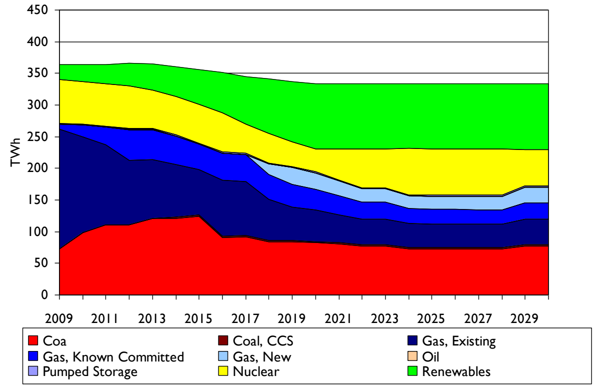
The Assumptions: Hurdle rates are increased by 3 percent relative to with EFC and EUA prices continue to rise slowly post-2020.

	2020		2030	
	Sensitivity	EFC	Sensitivity	EFC
Total renewables build (GW)	24.5	23.2	24.6	29.5
Total nuclear build (GW)	1.6	1.6	6.4	11.2
Total CCGT build (GW)	12.8	11.6	12.8	19.2
Total CCS build (GW)	0.3	0.3	0.3	6.3
Total unabated coal build (GW)	0.0	0.0	0.0	0.0
Total CO_2 emissions, mt CO_2	114	117	108	40
CO_2 intensity, g CO_2/kWh (demand)	340	350	320	120
Wholesale costs to consumer, £/MWh	95.59	94.67	119.41	108.03
Spill, GWh	0.00	0.00	0.01	0.35
Energy unserved, GWh	0.9	4.8	28.9	0.4
De-rated capacity margin, average in preceding five years, %	10.0	8.5	5.2	9.9
NPV of change in resource cost, excluding the cost of CO_2, relative to the EFC, £ million			N/A	

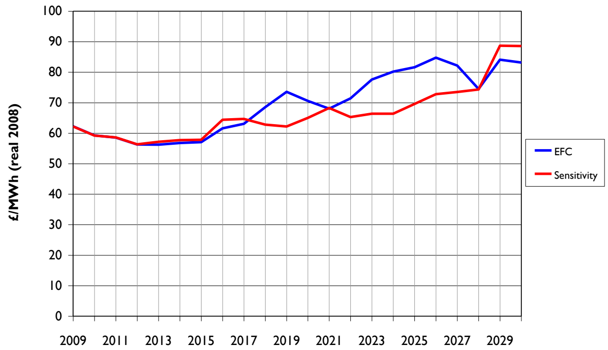
Build profile



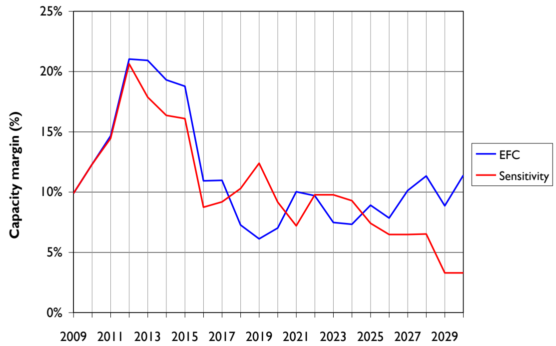
Generation, TWh



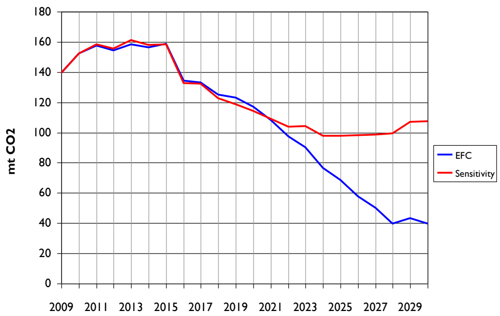
Annual average demand-weighted prices



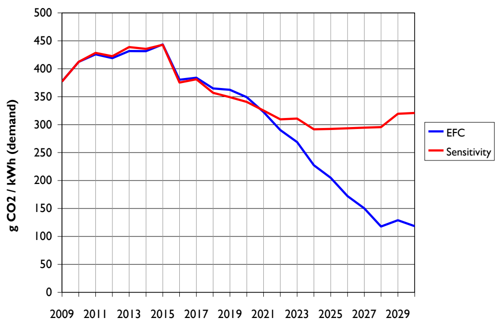
Capacity margin



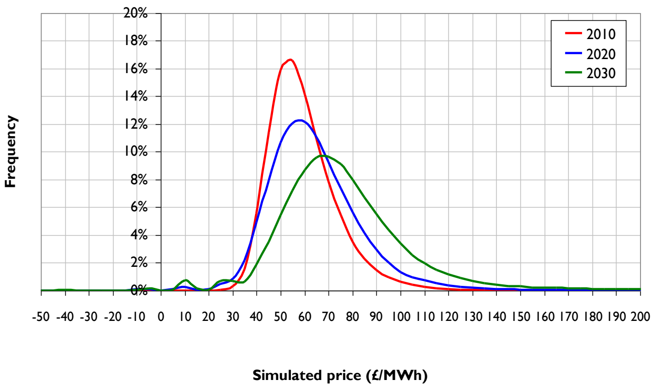
Total CO_2 emissions



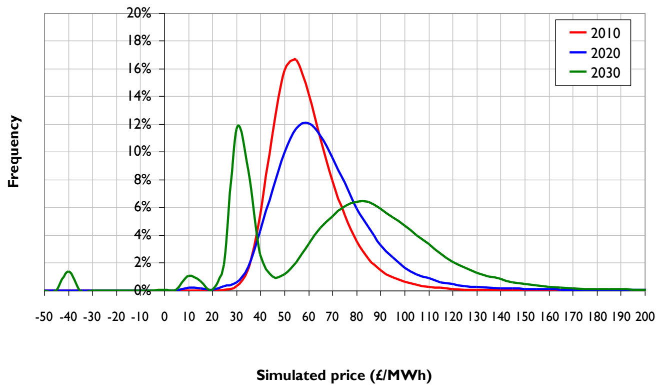
Emissions intensity



Price duration frequency, sensitivity



Price duration frequency, EFC

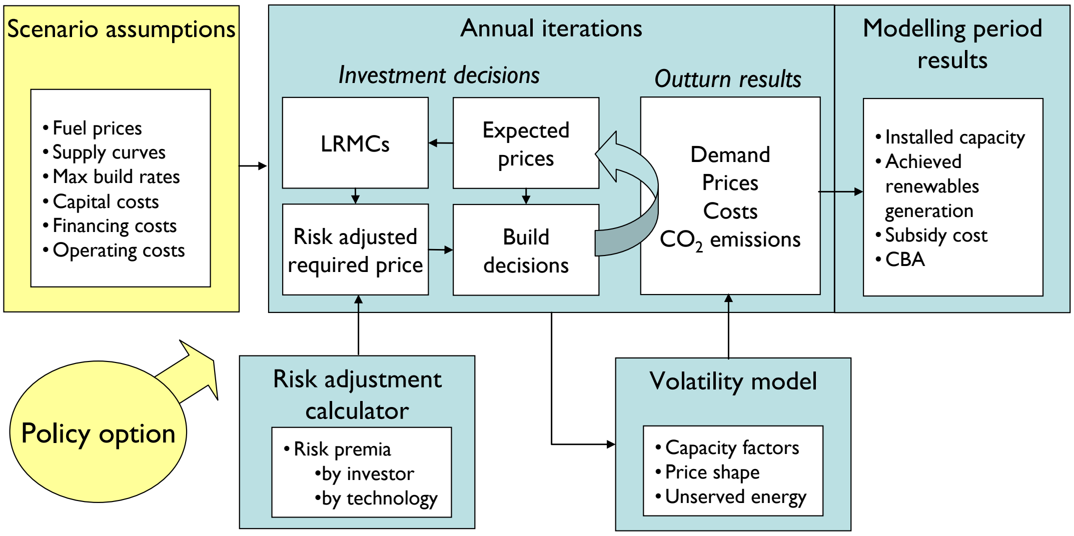


C Modelling approach

C.1 Overview

An overview of the modelling framework used for the study is shown schematically in Figure 57.

Figure 57 Modelling framework



At the heart of the framework lies an ***investment decisions*** simulator. This computes the risk-adjusted long run marginal costs (LRMCs) of all generation technologies by player type. Where these are less than expected revenues (given assumed load factors and future price expectations), players move new plant first to a planning stage, and subsequently, if still economic, to a committed development phase. On an annual basis, ***outturn results*** for demand, prices, generation output and carbon emissions are computed. These in turn feed back to expected prices for the following year's iteration.

The LRMCs used in the build decision algorithm are risk-adjusted in the ***risk adjustment calculator*** by computing a distribution of gross margins for each investment under the full range of uncertainties in revenues and project costs. The ***volatility model*** analyses the market at an hourly level for each year by simulating demand, spot fuel prices, forced outages and renewables output. It produces annual price duration curves and estimates of price volatility and volumes of short term demand side response and expected energy unserved. It is used to calibrate the expected price and renewables 'capacity credit' functions within the investment decisions simulator.

The modelling approach provides a comprehensive framework for the quantitative assessment of different support schemes and the impact of sensitivities. However, as with any modelling exercise, the limitations of the approach should be carefully considered. Key points to note include:

- The modelling requires multiple input assumptions including variables that are very uncertain such as commodity prices, future capital costs of plant, and maximum build rates.
- The modelling approach is dynamic and evolves prices and investment/retirements decisions through time in each run. This results in year on year variability as would be expected in reality. However, care should be used when comparing the results in individual years.

- The model estimates different hurdle rates for different technologies by simulating gross margin risk for a set of different investor types over the project lifetime. This is a simplified way to capture the complex interaction of factors that determine the cost of capital for different players in different technologies under different support schemes.
- We do not explicitly model specific transmission upgrade projects. We implicitly capture the cost impact of necessary transmission investments within the supply curve defined for each technology.
- We model plant operation on an unconstrained basis. In reality, transmission constraints could reduce the output from renewables plant and impact on the achievement of the renewables target.
- The model captures the evolution of market prices over time, and the impact on investment and retirements, in an internally consistent manner, taking into account the capacity margin and the mix and penetration of renewables on the system. However, there is huge uncertainty surrounding the market dynamics in a world of significantly higher renewables output.
- The model captures short term demand side response in determining expected energy unserved and peak prices. However, it does not endogenously include longer term demand side elasticity or changing shape in demand in response to evolving price signals: sensitivities were tested in which the change in demand shape was an exogenous variable.
- The volatility model incorporates part loading of thermal plant to account for uncertainty in demand and wind. Part-loading is constant across the day and is a function of the maximum wind output and maximum demand in the day.
- The volatility model captures the must-run of certain plant types. In addition to the intermittent (mainly wind) generation, the following are assumed to be 'inflexible' within day:
    - 10% of the CCGT fleet to reflect inflexibility due to physical and contractual reasons;
    - All existing nuclear capacity and 90% of new nuclear capacity;
- The model only covers the GB electricity market, and excludes Northern Ireland.

C.1.1 Simulating renewables output

Overview

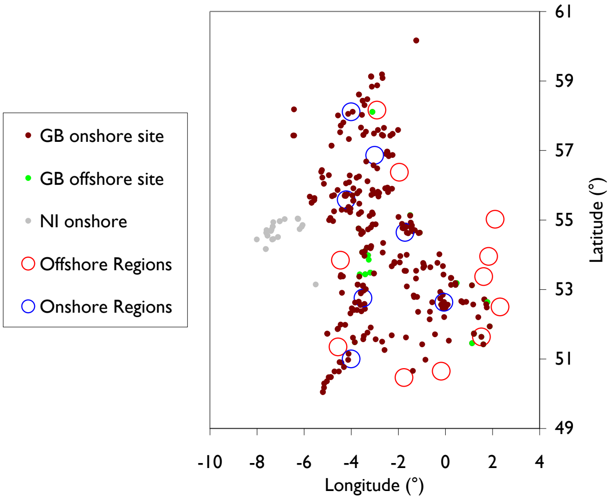
In this section of the Appendix we provide more details of how the variability of output from non-dispatchable intermittent renewables sources is modelled within the Volatility Model. The assumptions used impact the analysis of expected energy unserved and price duration curves, and the capacity credits used in the calculation of the de-rated peak capacity margins.

Wind

Volatility in wind output is simulated taking into account the different locations of wind plant, as well as the various seasonal patterns in output.

Correlation of wind output across the country is handled by allocating each wind farm notionally to different onshore and offshore 'regions'. The midpoints of the regions have been determined using the locations of operational and planned wind farms listed on the British Wind Energy Association website, with each of these existing wind plant then allocated to the region closest to its location. The total capacity allocated to a given region then determines the average proportion of new plant that will be added to that region within the simulation framework[74]

Figure 58 Regions used for modelling output of wind plant[75]



Output for each region, each day, is simulated using Weibull distributions, as per Gross et al (2006)[76]. The output across different regions is correlated through a function based on the approximate distance between the regions, parameterised using data published by Sinden (2007[77]).

The output is simulated around average levels which vary by month, according to the profile of historic UK capacity factors published by Sinden. The output within individual days also change rapidly from hour to hour, consistent with the rates of change in observed hourly wind output data, but as the number of days simulated increases, the average output levels for each hour of the day tend towards the seasonally-varying long-run hourly profiles in Sinden's paper.

The aggregation of wind plant to regions rather than simulating output from individual wind farms will tend to err on the side of conservatism and underestimate the diversity benefit and capacity credit of wind. This method was employed as correlating wind output across hundreds of individual wind farms, as well as simulating the rest of the GB market, would have increased the processing time within a Monte Carlo simulation framework to an impractical level.

Wave

The hourly output of wave plant is simulated following a similar logic to wind power. Individual wave plant are allocated to five different regions, located around the coast of Scotland and off the south-west of England, with the resource potential in each of the five regions based on information in a report on the variability of marine resources in the UK published by the Environmental Change Institute (ECI, 2005)[78].

[74] The locations and capacities of the offshore wind regions were modified using data relating to the tenders for offshore development in Rounds 1-3. Thus there is a prevalence of offshore wind capacity off the east coast of GB.

[75] Source: British Wind Energy Association (http://www.bwea.com/), Redpoint analysis

[76] Sinden, G. (2007). Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. *Energy Policy* **35**(1), 112-127.

[77] Gross, R., Heptonstall, P., Anderson, D., Green, T., Leach, M. and Skea, J. (2006). The Costs and Impacts of Intermittency. UK Energy Research Centre, London.

[78] Environmental Change Institute (2005). Variability of UK Marine Resources. Report commissioned by the Carbon Trust.

The output of the wave plant is correlated using a similar function to the wind plant (i.e. based on distance between regions), with the correlations calibrated against information in the ECI report. Average output levels for each month are profiled according to the same report; the outputs for each region are also sampled from a Weibull distribution[79].

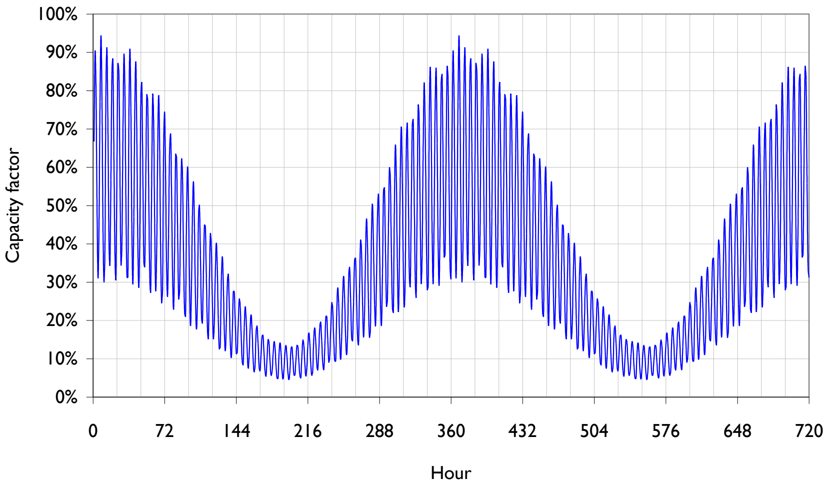
Tidal Stream

Unlike wave and wind, the output from tidal power plant can be predicted in advance. While tidal power output from any single plant varies dramatically during the day, the timing and scale of tides is very different across the country, providing a diversity benefit. However, due to the likely prevalence of development in one particular region (the Pentland Region in northern Scotland)[80], the hourly patterns in output are likely to be dominated by the tides in this region.

With a cycle repeating approximately each month, tidal plant experience two peak output periods (mean capacity factor approximately 65 percent per day) and two trough output periods (approximately 15 percent). This is referred to as the Spring-Neap tidal cycle[81]. The high-low tidal cycle also repeats approximately every 12.25 hours. Within each day, therefore, output is maximised approximately four times (there are two low and two high tides, and output is maximised in between the low and high tides).

These cycles combine to give an output profile stylised from the Environmental Change Institute report, shown in Figure 59.

Figure 59 Tidal stream aggregate capacity factors across a month



Within its Monte Carlo simulation framework, the Volatility Model simulates the aggregate output from all installed tidal stream plant for single days. Because the timing of Spring tides falls within approximately the same two-hour window in each Spring-Neap cycle, approximately the same output cycle repeats itself every fifteen days. Therefore, for each of the individual days simulated, one of the fifteen daily output profiles is selected. The same point in the Spring-Neap cycle is selected for both stream and range

[79] Such assumptions are unlikely to have a material impact on the results of this study, due to the relatively small amount of wave power that can be deployed by 2020.

[80] This information comes from the Environmental Change Institute report. Recent advances in tidal stream generating technology may facilitate power generation in a wider variety of locations.

[81] The half-yearly cycle that gives rise to the largest Spring tides, approximately at the time of the March and September equinoxes, has not been modelled.

capacity. The profiles simulated also maintain the correct timing relationship between the hourly profiles across the stream and range capacity.

Tidal Range

Tidal range plant in GB may be spread across a number of locations, and use a range of different technologies and configurations. For this reason, we assume that the output from tidal range projects is well diversified and hence for simplicity have assumed that it is constant across the day simulated.

The capacity credit of tidal range has been calculated in the same way as those of the other intermittent renewable plant. The assumption that aggregate tidal range output is constant across the day (and varies only with the Spring-Neap cycle) results in its capacity credit being approximately equal to its annual capacity factor.