MAY 2012

LCP's assessment of the dispatch distortions under the Feed-in Tariff with Contract for Differences policy.

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This Final Report has been prepared by Lane Clark & Peacock LLP ("LCP") for the Department of Energy and Climate Change ("DECC"). It constitutes LCP's assessment of the extent of the potential dispatch distortions as a result of the design choices proposed by the Government under the Feed-In Tariff with Contract for Differences policy and identifies possible policy options to mitigate the issues identified.

Executive summary

Introduction

The UK Government's Electricity Market Reform ("EMR") aims to deliver a new market framework that enables effective and efficient delivery of secure supplies of low carbon electricity. One of the policy packages the Government is intending to introduce is a Feed-in Tariff with Contract for Difference ("CfD"). The aim of this policy is to decarbonise the electricity supply by promoting investment in low carbon generation at least cost to consumers.

A CfD sets a fixed pre-agreed level ("the strike price") under which variable payments are made to top-up the level of payment for the duration of the contract. The 'top-up' payment is based on a yet to be determined reference price. The CfD is a two way mechanism that has the potential to see generators return money to consumers if wholesale electricity prices are higher than the strike price.

There are two CfD designs that the Government are considering which depend on the characteristics of the technology being supported. Specifically there is one CfD structure for intermittent generation and one for baseload, each with different reference prices.

Proposed design choices for CfD

	Intermittent CfD	Baseload CfD
Contract Form	Two-way CfD	Two-way CfD
Strike Price Indexation	Annual inflation indexation	Annual inflation indexation
Market Reference Price	Day-ahead price Choice of baseload or hourly prices Not averaged over a longer period	Year-ahead price Choice of price sources
Contract Volume	Metered output	Metered output or firm volume

Source: DECC White Paper July 2011, Annex B, p.151

Scope of the report

The purpose of the modelling and analysis LCP has undertaken for DECC is to help policy makers to understand any potential distortions which might arise to dispatch decisions as result of these design choices. Distortions in this context are CfD supported plant generating when wholesale prices are below plant-specific marginal costs.

DECC's particular interest is the likelihood and timing of negative prices, as frequently occurring negative prices would incur significant additional costs to the UK tax-payer and ultimately the consumer, due to inefficient system operation. The dispatch impacts of a high wind day are of significant concern. For example, in Germany, power plants under the premium feed-in tariff system have no incentive to stop generating in response to very low market prices, illustrating a very real market design issue.

Distortions can arise in both a static and dynamic basis. The static issue is whether or not the existing generation base is efficiently dispatched at the lowest system-wide cost. Different designs will also have dynamic impacts on investment incentives and hence on the plant mix that is dispatched in the future.

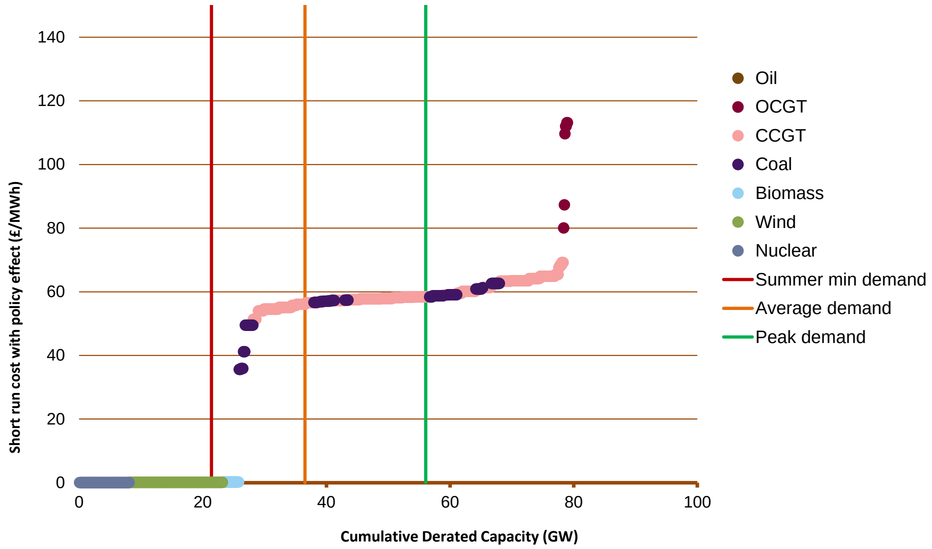
To analyse these issues LCP undertook deterministic scenario analysis to map a range of possible futures. LCP's EnVision model was utilised to deliver the analysis of the proposed CfD design choices under different scenarios agreed with DECC. The focus of the analysis was on reference prices and how contract volumes should be determined.

There are a number of assumptions that underpin the analysis and modelling and unless otherwise stated all data and assumptions are in-line with DECC's central assumptions. There are also a number of uncertainties associated with the outputs from the modelling, which were assessed via sensitivity analysis.

2135593 **High wind and minimum system demands impact prices**

Power markets consist of differing technologies to generate electricity, with generally inelastic demand in the short term. The differing economics of power generating technologies combined with high wind and minimum system demands impacts prices.

Projected merit order stack in 2020 with pre-EMR policies



Source: LCP

At a given demand more wind plant on the system implies a lower price for power because the market clears with generation plants that have a lower marginal cost. However, the impact of increased wind power supply on price will depend on the time of day and year, for example:

- If a period of high wind combines with a period of peak power demand, all available wind generation can be utilised.
- However, if the period of high wind combines with a period of minimum demand (e.g. overnight during the summer), available wind generation may need to be curtailed.

Choice of reference price

The reference price selected for the CfD can potentially have a significant impact on operation of the plant covered by the contract, which in turn impacts wholesale market prices. In choosing the reference price there are a number of factors to consider:

- *The depth of the market* – The chosen wholesale power market should have sufficient liquidity to provide a stable, reliable reference price.
- *The strength of the hedge it offers investors* – For the CfD to provide a strong hedge the reference price should either be a market in which plant can sell their output or a close approximation to the markets where the power is actually sold.
- *Avoiding market distortions and opportunities for gaming* – The potentially large volume of intermittent generation that will be subject to a CfD may lead to distortions in the reference market depending on the choice of reference price and how the CfD is implemented.

The Government's proposed market reference price for intermittent CfDs is day-ahead with a choice of either baseload or hourly prices. In the analysis that has been undertaken for DECC, three possible types of day-ahead reference prices were considered:

- Baseload;
- Electricity Forward Agreement ("EFA") blocks; and
- Half-hourly.

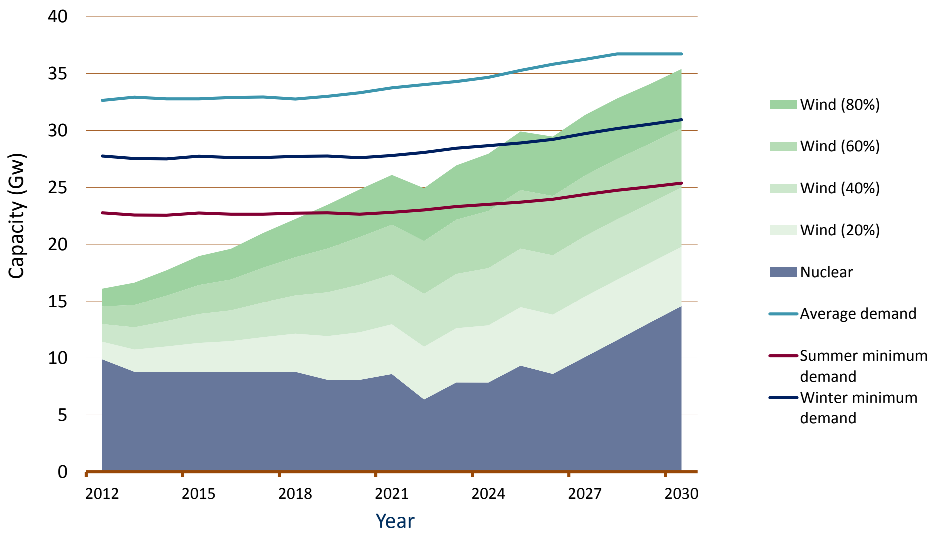
Factors affecting negative price frequency and severity

Intermittent generators selling their power in forward wholesale power markets are able to sell down to a price negative of their support level. This means that their total income remains positive once the support level is taken into account. Negative prices will occur when the price setter in the wholesale market is willing to sell their power at a loss in order to receive the subsidy payment.

Overall, there are two principal factors that will increase the likelihood and impact of negative prices:

- Minimum system demands; and
- Increased penetration of low marginal cost plant that will keep running to access support payments.

Projected inflexible generation at different wind load factors, 2012 to 2030



Source: LCP

Over the period 2018 to 2030 increased penetration of wind plant means that there is a potential overcapacity of inflexible generation at high load factors. Wind generation output may therefore need to be curtailed when periods of high wind coincide with summer minimum demands.

Market operation and distortions

There could be significant distortions for intermittent CfD plant depending on the choice of the day-head reference price:

- *Day-ahead baseload:* In this market it is unlikely that wind plant would ever become price setting.
- *Day-ahead half hourly:* If in any half hour period it is expected that inflexible generation exceeds demand wind plant may become price setting.

The distortion under day-ahead EFA blocks reference price would be some-way between the two.

Interactions with other renewable policies

The CfD regime will operate alongside the current system of supporting renewables in the UK, the Renewables Obligation (“RO”).

In periods where wind generating plants are sufficient to meet demand, there is a potential for wind plant to compete for the right to generate to receive their subsidies. This materialises in negative prices in the market.

With ROCs, the minimum market price at which they will be willing to generate is equivalent to the negative of the ROC price they expect to achieve.

Scenarios

Two generation mix scenarios were agreed with DECC and analysed:

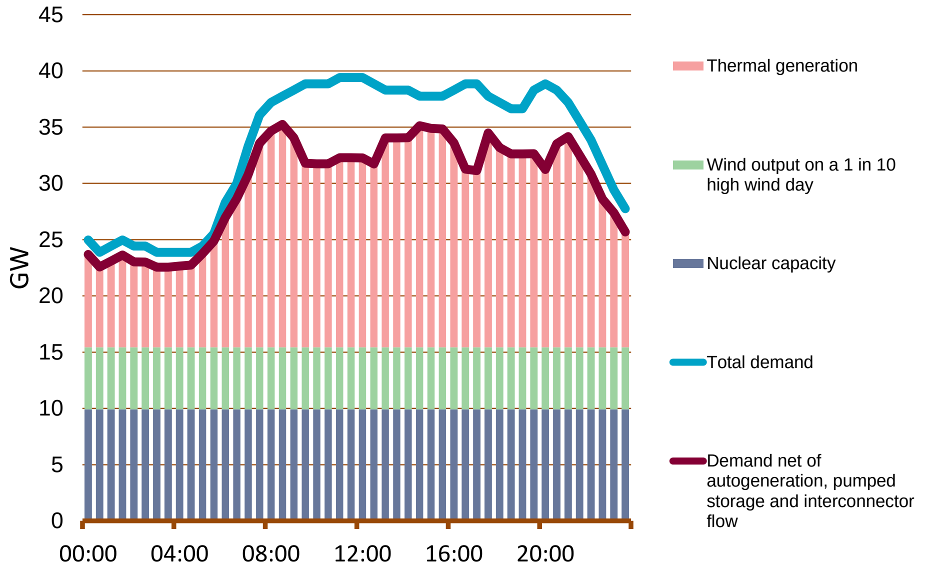
- *Base case scenario ("Base case"):* this utilises DECC's central assumptions for commodity prices, demand, plant construction and operating costs, and required investor returns. It assumes RO / CfD support rates are set to bring on relatively lower amounts of wind onto the system.
- *High wind installed capacity scenario ("High wind"):* this also utilises DECC's central assumptions but assumes RO / CfD support rates are set to bring on a relatively higher amount of wind onto the system.

Base case: Results

The base case results illustrate that when there is sufficient thermal plant available, the system operator has at its disposal enough back-up flexible thermal generation to reduce the amount of generation output there is on the system.

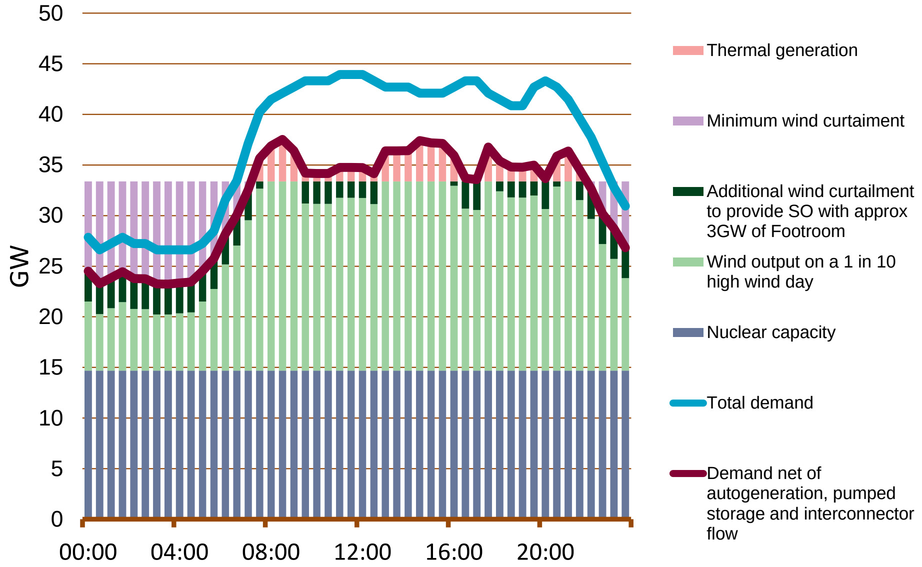
However, as wind deployment increases dramatically out to 2030, the system operator will need to take action to curtail wind generation in periods of high wind.

Base case – High wind and low demand day, 2012



Source: LCP

Base case – High wind and low demand day, 2030

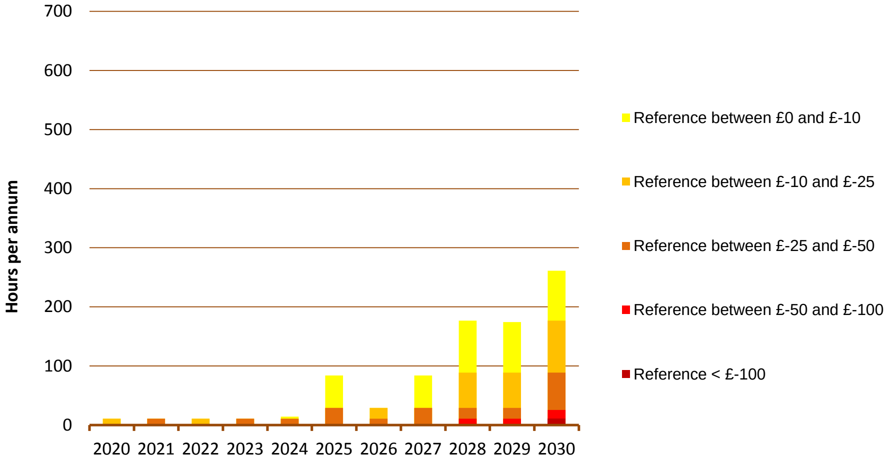


Source: LCP

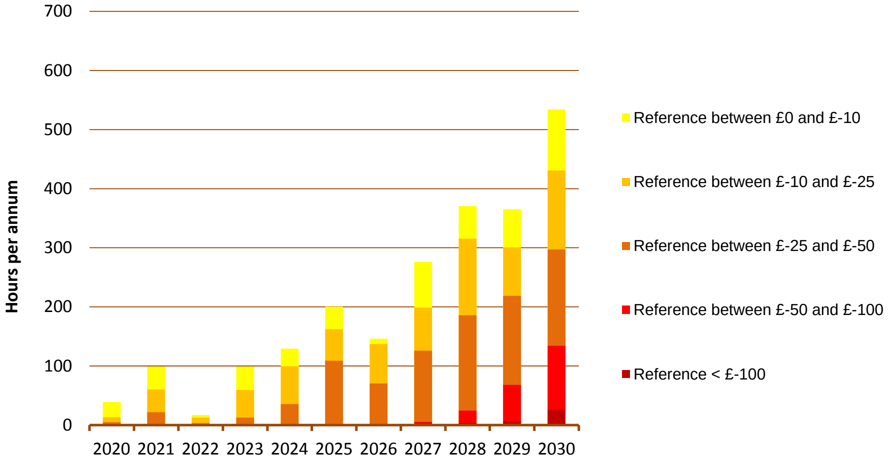
The impact of having different types of day-ahead reference price was analysed by looking at the projected frequency (i.e. how often) and severity (i.e. the extent) of negative prices in the reference and day-ahead half-hourly wholesale spot power markets. Spot prices were analysed because if, at the day-ahead stage, projections for wind output and demand are accurate then day-ahead half hourly prices are equivalent to the wholesale spot prices for that period.

The analysis highlighted the magnitude of the distortion does depend on the day-ahead reference price chosen with the reference price market distortion least for baseload and highest for half-hourly. The following three figures illustrate the degree and severity of negative day-ahead baseload, EFA blocks and half-hourly reference prices for the period 2020 to 2030.

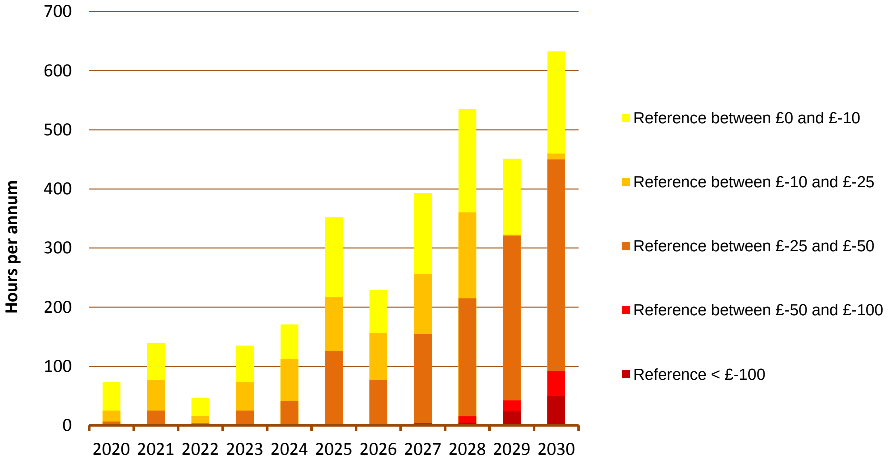
Base case – Day-ahead baseload reference price, 2020 to 2030



Base case – Day-ahead EFA blocks reference price, 2020 to 2030



Base case – Day-ahead half-hourly reference price, 2020 to 2030



Source: LCP

In terms of impact on wholesale spot power prices, the results were not as conclusive with the overall frequency of negative prices broadly the same across the three day-ahead reference prices considered, although the severity of the impact appears to be less for baseload. The following table illustrates both how often prices are negative (i.e. the total number of hours per annum less than £0) and the severity of the impact (e.g. less £0 but greater than or equal to minus £25, etc.) in 2030 for baseload, EFA block and half-hourly reference prices.

Base case – Degree and severity of negative wholesale spot power prices, Hours per year, 2030

Price range	Baseload	EFA block	Half-hourly
£0 to -£25	210	184	182
-£25 to -£50	350	357	357
-£50 to -£100	48	43	43
Less than -£100	22	49	49
Total	629	633	631

Source: LCP

High wind: Results

Our analysis highlights, when compared to the base case, a higher rate of wind deployment increases the magnitude of the distortion significantly.

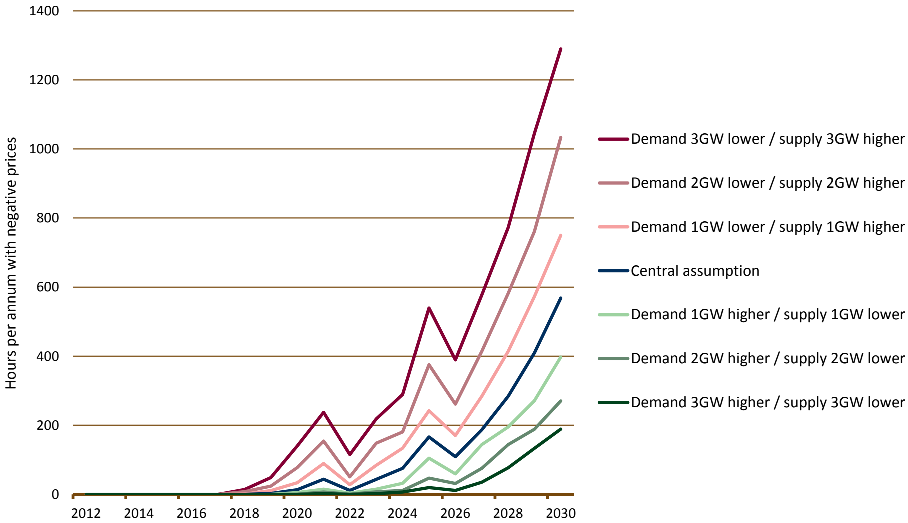
Sensitivity of base case results

There are a number of uncertainties associated with the analysis concerning:

- The availability and flexibility of nuclear generation;
- The availability and flexibility of interconnection;
- The availability of storage technologies;
- The volume of demand side response; and
- The volume and flexibility of embedded generation.

To illustrate the sensitivity of the base case day-ahead half-hourly spot price results, the following figure shows how the number of negative price hours is impacted by the level of demand or supply adjusted by minus 3GW, minus 2GW, minus 1GW, plus 1GW, plus 2GW and plus 3GW.

Sensitivity of base case day-ahead half-hourly spot price results



Source: LCP

Overall, the sensitivity analysis illustrates that relatively small changes can have significant impacts on the modelling results, with negative price distortion more sensitive to reducing demands / increasing inflexible supply than rising demands / lower inflexible supply.

Mitigating policy options

The purpose of the modelling and analysis that has been undertaken for DECC is to help policy makers understand which reference price to use and how contract volumes should be determined.

The intermittent CfD analysis shows that negative reference and wholesale prices are unlikely to become an issue until the 2020s. The magnitude of the distortion in the 2020s does depend on the day-ahead reference price chosen with the reference price market distortion least for baseload and highest for half-hourly. A higher rate of renewables deployment and penetration increases the magnitude of the distortion significantly.

The Government's preferred method for determining the contract volume under intermittent CfDs is metered output which bases the contract volume on the metered output of the plant. There are, however, alternatives which mitigate the distortions identified by the modelling:

- The first option is to have payments based on availability, where the CfD generator only receives the support if they are available to generate.
- The second option is to cap the support at the strike price, where the CfD plant does not generate if prices drop below negative the strike price.

The advantages and disadvantages of these two approaches are set in the table below.

Policy options for intermittent CfDs

	Payments based on availability	Capping the support at the strike price
Advantages	▪ Reduces the cost to the system operator to constrain wind	▪ Intermittent CfD plant will not generate if prices drop below negative of strike price
Disadvantages	▪ Practically difficult to measure theoretical output, especially simulating when cut-off is likely ▪ Costs of monitoring equipment and administration	▪ ROC plant gain preference over CfD plant ▪ Possible increase to strike prices if investors perceive a high frequency of negative prices ▪ System operator still required to compensate for lost output when they need to constrain plants covered by CfD

Source: LCP

Firm volume versus metered output

The Government is considering two options for determining the volume of electricity under the baseload CfD for which the generator can receive support:

- *Metered output:* This bases the contract volume on the metered output of the plant.
- *Firm volume:* This bases the contract on a pre-agreed firm volume.

Market operation and distortions

The following factors could affect the likelihood of market distortion:

- The capacity of mid-merit plant contracted under a CfD;
- The position of the CfD plant in the merit order; and
- The differential between the strike price and reference price.

Interaction with other renewable policies

In theory, there would appear to be the potential for ROC and CfD plant to be competing to generate although this would require a large per MWh subsidy payment which alters their position in the merit order.

If wind was paid on availability, there could be a scenario where negative prices mean that wind stops generating and biomass, under a large per MWh payment, is running. This would seem to be a perverse outcome and likely to be inefficient.

Scenarios

Under the base case assumptions, the analysis found the distortion caused by baseload CfDs to be negligible. This is because:

- There are low levels of mid-merit CfD deployment.
- Biomass and gas CCS generating plant sit firmly between the inflexible plant (i.e. wind and nuclear) and the flexible plant (i.e. conventional thermal plant with higher short-run marginal costs). It would therefore require a large per MWh payment from the CfD to change their position in the merit order.
- Projected wholesale power prices are not significantly lower than the strike price.

Further scenario analysis with a higher deployment of installed biomass and gas CCS capacity did not find any significant distortions under a metered output basis.

CONCLUSIONS

Intermittent CfDs

Overall, for intermittent CfDs the modelling and analysis highlights that the choice of reference price impacts the frequency and severity of negative prices although these are unlikely to be an issue until in the 2020s. During the 2020s the reference price market distortion is least for baseload and highest for half-hourly. A higher rate of renewables deployment and penetration increases the magnitude of the distortion significantly. There are policy options to mitigate these impacts, each with their own distinct advantages and disadvantages.

The analysis presented for intermittent CfDs is sensitive to relatively small changes in the assumptions which potentially having significant impacts on the results. Our sensitivity analysis highlights the negative price distortion is more sensitive to reducing demands / increasing inflexible supply than rising demands / lower inflexible supply.

Baseload CfDs

Overall, for baseload CfDs the modelling and analysis did not find any significant distortions due low levels of mid-merit CfD deployment; mid-merit plant sit firmly between the inflexible and flexible plant; and projected wholesale power prices not being significantly lower than the strike price.

The fuel price assumptions underpinning the analysis are based on DECC's current projections. Since the modelling and analysis was undertaken by LCP, DECC has updated its biomass price projections. This is likely to affect the role played by biomass and the possible implications of this are briefly explored in an Addendum in Appendix E.

1. Introduction

1.1. Background

The UK's electricity generation sector will need to dramatically reduce its carbon intensity in order to achieve 2030 renewable targets and to be consistent with long-term carbon reduction goals.

The UK Government's Electricity Market Reform ("EMR") aims to deliver a new market framework that enables effective and efficient delivery of secure supplies of low carbon energy. The policy packages and aims pursued by the UK Government are:

- *Carbon price support:* Strengthening the carbon price for electricity generators will increase the cost of fossil fuel generation, making lower carbon power more attractive;
- *Feed-in tariffs:* Long-term contracts based on a 'contract for difference' model provide more certainty on the revenues for low-carbon generation, making clean energy investment more attractive;
- *Capacity payments:* Targeted payments to meet the security of supply challenges posed by flexible generating plant retirements and the increasing amount of intermittent and inflexible low-carbon generation. The aim is to incentivise the construction of flexible reserve plants or demand reduction measures; and
- *Emissions Performance Standard:* A back-stop limit on how much carbon the most carbon intensive new power stations - coal and gas - can emit.

These various changes in UK energy policy create both risks and opportunities for energy companies, investors and policy makers.

1.2. Scope of this report

The purpose of the modelling and analysis LCP has undertaken for DECC is to help policy makers understand how Feed-In Tariffs with Contract for Difference ("CfDs") should be structured so that CfD supported plant have an incentive to stop generating when wholesale electricity prices are below plant-specific marginal costs.

DECC's particular interest is the likelihood and timing of negative prices. The concern is that if such action is only taken against over payment (over and above any payments arising from the balancing mechanism), then frequently occurring negative prices would incur significant additional costs to the UK taxpayer and ultimately the consumer, due to inefficient system operation.

The likelihood and timing of negative prices under different CfD designs is only part of the issue as dispatch distortions can arise in both a static and dynamic settings. The static issue is whether or not the existing generation base is efficiently dispatched at the lowest system-wide cost. Supply-side responses also have dynamic implications, as different CfD designs will impact on the investment incentives facing market participants and potential new entrants, and hence on which plant mix is dispatched in the future.

To analyse these issues LCP undertook deterministic scenario analysis to map out a range of possible futures. LCP's EnVision model was utilised to deliver analysis of the proposed design choices for CfDs under different scenarios. The assumptions underpinning the modelling, which were agreed with DECC, are set out in Appendix B.

There are a number of uncertainties associated with the outputs from the modelling, which were assessed via sensitivity analysis.

Structure of this report

This report constitutes the Final Report of LCP's assessment of the extent of the dispatch distortions under both intermittent and baseload CfDs and identifies possible policy options to address the issues the modelling and analysis identifies.

The Final Report is structured as follows:

- Section 2 outlines the policy background for CfDs, the proposed design options and the definitions of different methods of determining the volume of electricity under CfDs i.e. metered output, firm output and availability.
- Section 3 outlines the differing economics of power generating technologies, how high wind impacts the power supply curve and how in turn, under differing system demands, this impacts prices.

The Final Report is then organised into two main areas looking first at intermittent CfDs and then baseload CfDs.

- For intermittent CfDs, the Final Report is organised as follows:
    - Section 4 outlines the specific characteristics of wind generation and the incentives that result due to these characteristics.
    - Section 5 then discusses the factors that will need to be taken into account in choosing an appropriate reference price for intermittent CfDs.
    - Section 6 identifies the principal factors that can affect negative price frequency and severity for intermittent CfDs.
    - Section 7 discusses the distortions for intermittent CfD plants that result from different references prices.

  - Section 8 discusses likely intermittent CfD interactions with other renewable policies.
  - Section 9 outlines the scenarios and presents the analysis undertaken for intermittent CfDs under two generation mix scenarios.
  - Section 10 presents the sensitivity of the intermittent CfD results.
  - Section 11 discusses the possible policy options to mitigate the distortions identified.
  - The final section sets out the conclusions that can be drawn from the modelling and analysis.
- For baseload CfDs, the Final Report is organised as follows:
  - Section 13 outlines the specific characteristics of baseload and mid-merit generation and the incentives that result due to these characteristics.
  - Section 14 then discusses the factors that will need to be taken to account for contracted volume for baseload CfDs.
  - Section 15 discusses the potential distortions for baseload CfD plants.
  - Section 16 discusses potential baseload CfD interactions with other renewable policies.
  - Section 17 outlines the scenarios and presents the analysis undertaken for baseload CfDs.
  - Section 18 discusses possible more extreme long-term distortions under baseload CfDs.
  - Section 19 discusses the long-term possibility of negative prices under baseload CfDs.
  - The final section on baseload CfDs sets out the conclusions that can be drawn from modelling and analysis.
- Appendix A provides a brief overview of LCP's EnVision, the model utilised to deliver the deterministic scenario analysis of the proposed design choices for CfDs.
- Appendix B outlines the assumptions underpinning the modelling.
- Appendix C presents the wind duration curves that were utilised.
- Appendix D presents the daily load curves that were utilised.
- Appendix E presents an addendum to the analysis based on DECC's updated biomass projections.

2. Background

2.1. Policy background

DECC announced in the July 2011 EMR White Paper its intention to introduce a Feed-in Tariff with Contract for Difference. The aim of this policy is to decarbonise the electricity supply by promoting investment in low carbon generation at least cost to consumers.

The White Paper outlined the high level design characteristics of the CfD, including having different design structures depending on the characteristics of the technology being supported. Specifically there is one CfD structure for intermittent generation (referred to as “intermittent CfDs” throughout this report) and one for baseload generation (referred to as “baseload CfDs”), each with different reference prices and design characteristics.

As part of the implementation of the CfD mechanism, DECC wishes to explore the effects of removing the incentives for CfD-supported plant to run when wholesale prices fall below the marginal cost of a supported plant.

2.2. Proposed CfD design options

The CfD sets a fixed pre-agreed level (“the strike price”) under which variable payments are made to top-up the level of payment for the duration of the contract.

The CfD entitles the generator to receive the strike price less a yet to be determined reference price. This payment would be made in addition to the generator’s revenues from selling electricity in the market.

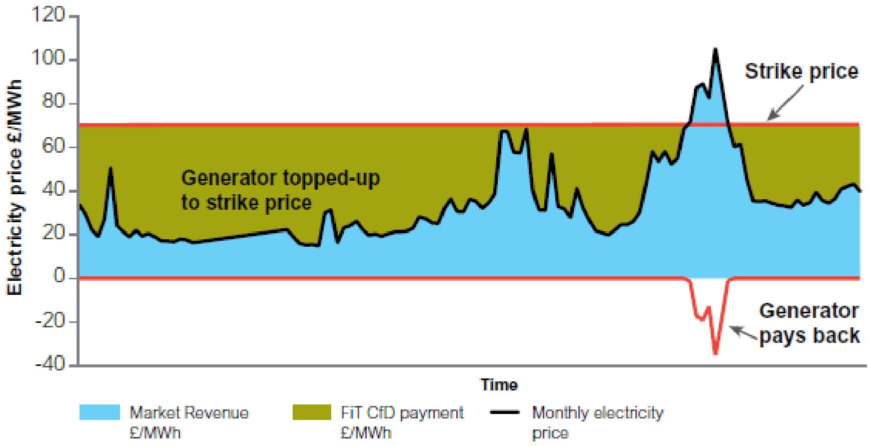
The CfD is a two way mechanism that has the potential to see generators return money to consumers if wholesale electricity prices are higher than the strike price.

A CfD can be applied to all types of generation, although the design of the mechanism needs to recognise the characteristics of the plant being supported such as baseload, intermittent and flexible plant.

- Baseload plant operates at a constant level of generation, either for economic reasons or the plant has limited ability to vary output at short notice to respond to shifts in demand. This type of plant includes nuclear as well some biomass plant and Carbon Capture and Storage (“CCS”) plant.
- Intermittent plant has little or no control over when it generates or at what level. This type of plant includes wind as well as other renewable technologies such as wave and solar.
- Flexible plant has the ability to control its output and respond to shifts in demand in different timeframes.

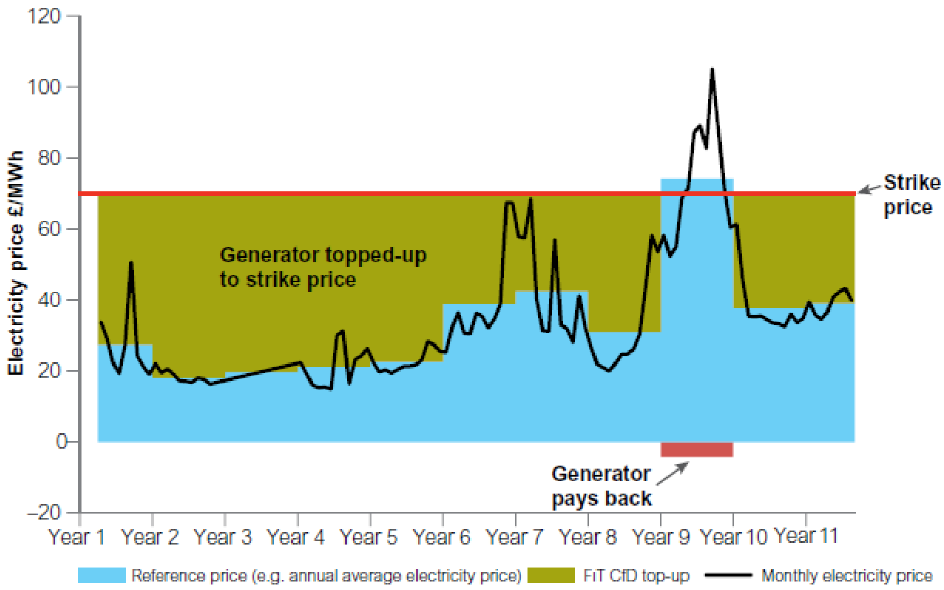
Figures 2.1 and 2.2 illustrate the operation of intermittent and baseload CfDs.

Figure 2.1: Operation of intermittent CfDs



Source: DECC White Paper July 2011, p. 38

Figure 2.2: Operation of baseload CfDs



Source: DECC White Paper July 2011, p. 38

The different characteristics of the plant mean that that cost and benefits of different CfD structures vary. Which reference price to use and how contract volume should be determined are key design choices that affect the efficiency of the CfD for different generation types.

Table 2.1: Proposed design choices for CfD

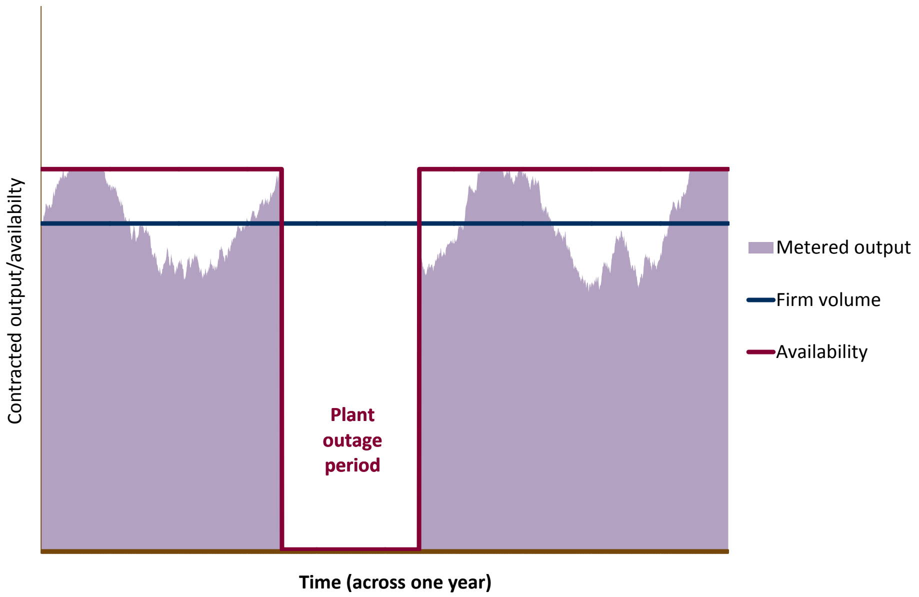
	Intermittent CfD	Baseload CfD
Contract Form	Two-way CfD	Two-way CfD
Strike Price Indexation	Annual inflation indexation	Annual inflation indexation
Market Reference Price	Day-ahead price Choice of baseload or hourly prices Not averaged over a longer period	Year-ahead price Choice of price sources
Contract Volume	Metered output	Metered output or firm volume

Source: DECC White Paper July 2011, Annex B, p.151

2.3. Definitions of different methods of determining the volume of electricity under a CfD

The Government is considering different options for determining the volume of electricity contracted under the CfDs. Figure 2.3 illustrates the three principal methods: metered output, firm volume and availability.

Figure 2.3: Different methods of determining the volume of electricity under a CfD



Source: LCP

The three methods for determining the contract volume are:

- *Metered output:* This bases the contract volume on the metered output of the plant. As illustrated in figure 2.3, for certain generating plant actual output will alter throughout the year. A CfD generator under a metered output contract will therefore only receive support for actual electricity generated and will not receive any support when there is a plant outage or when it is not generating for economic reasons. Under metered output, the level of support is therefore equivalent to volume of electricity generated multiplied by the strike price minus the reference price. It is one of two options being considered for baseload CfDs (the other option being firm volume).
- *Firm volume:* This bases the contract volume on a pre-agreed firm volume. A CfD generator under a firm volume contract will therefore receive support irrespective of the amount of electricity generated and they could receive support when there is a plant outage. Under firm volume, the level of support is equivalent to the pre-agreed firm volume of electricity to be generated multiplied by the strike price minus the reference price. The volume would be set taking into account expected outage rates and average availability, i.e. the plant's derated capacity. This method is one of two options the Government is considering for baseload CfDs (the other being metered output).
- *Availability:* This bases the contract volume on the availability of the plant. A CfD generator under an availability contract will only receive support if they are available to generate. This would mean they would not receive support if there was a plant outage but would if the plant was not generating for economic reasons. Under availability, the level of support is equivalent to the availability volume multiplied by the strike price minus the reference price.

If the actual rate of plant outages in every year is in-line with the firm volume of a contract then firm volume and availability contracts provide the same revenue. Similarly if a plant is running only as baseload (e.g. nuclear) then metered output and availability provide the same revenue stream.

3. Supply and demand in power markets

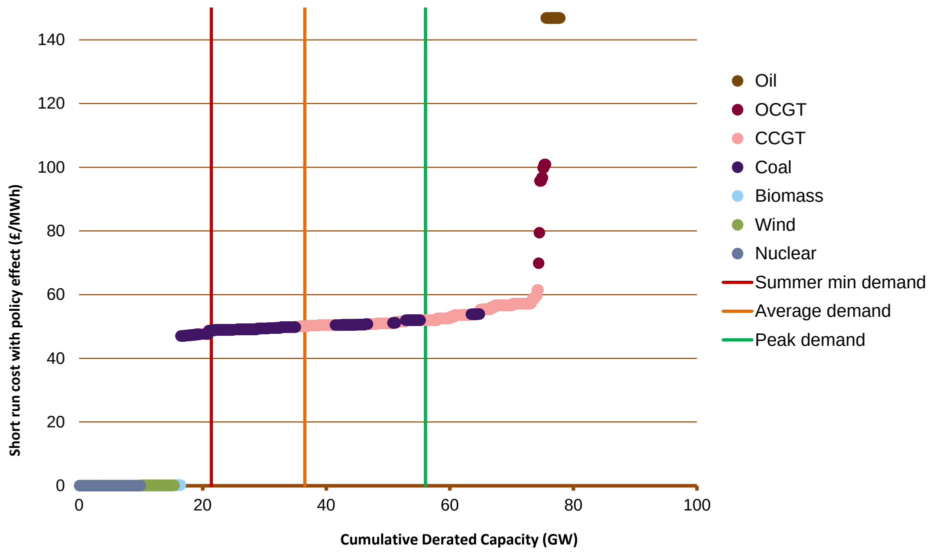
This section outlines the differing economics of power generating technologies, how high wind impacts the power supply curve and how, in turn, under differing system demands, this impacts prices.

3.1. Power supply curve

The power supply portfolio is made up of a range of generating technologies including nuclear, wind, biomass, coal, gas (i.e. combined cycle gas turbine ("CCGT") and open-cycle gas turbine ("OCGT" plant)), and oil plant. The ordering of these technologies depends on the amount of power they can supply and the marginal cost of this power. The differences in costs reflect the technology used to generate power, the input fuel and the cost of CO_2 emissions. Additionally, if a generator receives a payment for each unit of output (e.g. wind and biomass receive a subsidy under the Renewables Obligation ("RO")) then the price at which the plant will be willing to generate will allow for the policy revenue lost if the plant were not generating

Figure 3.1 shows the projected demand and supply curve for the GB power market in 2012 with current implemented policies taken into account.

Figure 3.1 Merit order stack in 2012 with pre-EMR policies



Source: LCP

As illustrated in figure 3.1, nuclear and wind power enter the supply curve at the lowest level, due to their low marginal costs, followed by biomass, coal, gas CCGT and gas OCGT and oil. In this example biomass is shown at £0 per MWh. This is because the current ROC subsidy received by these plants is covering the short term fuel costs so it is profitable for them to generate even if the price fell to £0 per MWh. Oil plants have the highest marginal cost of power production and rarely generate.

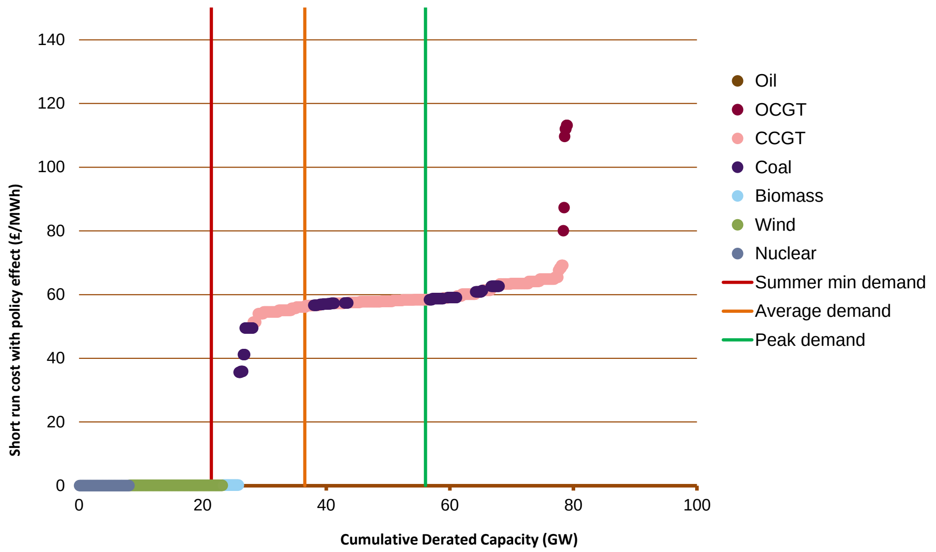
Figure 3.1 also illustrates peak, average and summer minimum demand. As demand is inelastic minor changes in supply can result in major price changes.

3.2. Impacts of high wind

In periods of high wind the power supply curve shifts to the right when the power supply from existing wind plant increases.

Adding more wind capacity into the generation mix will also shift the supply curve, as illustrated by figure 3.2 which shows the projected merit order stack with current implemented policies taken into account for 2020.

Figure 3.2: Projected merit order stack in 2020 with pre-EMR policies



Source: LCP

At a given demand more wind plant on the system implies a lower price for power because the market clears with generation plants that have a lower marginal cost. However, the impact of increased wind power supply on price will depend on the time of day and year:

- If a period of high wind combines with a period of peak power demand, all available wind generation can be utilised.
- However, if the period of high wind combines with a period of minimum demand (e.g. overnight during the summer), available wind generation may need to be curtailed.

ANALYSIS OF INTERMITTENT CFDS

The following sections focus on intermittent CfDs and outline:

- The specific characteristics of wind generation[1] and the incentives that result due to these characteristics.
- The factors that will need to be taken to account in choosing an appropriate reference price for intermittent CfDs.
- The principal factors that can affect negative price frequency and severity for intermittent CfDs.
- The distortions for intermittent CfD plants that result from different reference prices.
- CfD interactions with other renewable policies.
- The scenarios and analysis undertaken for intermittent CfDs under two generation mix scenarios.
- Sensitivity of the analysis.
- Possible policy options to mitigate the distortions identified.
- Conclusions that can be drawn from the modelling and analysis.

The next section outlines the issues for wind generators and the incentives that result.

4. Issues for intermittent wind generators

Wind power generation has specific characteristics:

- It has a highly variable output with a low load factor – DECC's central assumptions assume an average of 30 per cent for onshore wind and 40 per cent for offshore.
- It cuts out at high wind speeds to protect the integrity of the blades and turbine.
- It is difficult to forecast output accurately.

Wind generation also carries with it various non-specific risks including construction, market and technology risks.

As a result, many independent wind generators enter a Power Purchase Agreement (PPA)[2] with large vertically integrated energy utilities and other major power purchasers to pass on many of the risks e.g. balancing risks associated with wind generation.

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[1] Whilst the analysis focuses on wind, it is also relevant for solar and marine power generation, although these are not significant at the moment.

Wind generators without a PPA will need to sell their power as close as possible to real-time dispatch in order to minimise uncertainty and attempt to match their forecast output as closely as possible.

Given the unpredictability ahead of dispatch, the wind generator once contracted at the day-ahead stage will fine tune its position by either buying or selling on the wholesale market or, if the wind generation is part of a portfolio, by adjusting the generation of other flexible generating plant.

If a wind generator holds a two-way CfD for their intermittent wind generation output, they are responsible for selling their output to achieve the best price in the market place, and in return will receive the difference between the strike price and reference price. Given the specific characteristics of wind generation, CfD wind generators have strong incentives to sell in the day-ahead half-hourly market. Studies have found that accuracy of wind power forecasting over a 36 hour horizon is 'fairly good'[3].

5. Choice of intermittent CfD reference price

The reference price selected for the CfD can potentially have a significant impact on operation of the plant covered by the contract, which in turn impacts wholesale market prices. In choosing the reference price there are a number of factors to consider:

- *The depth of the market:* It is important that the chosen wholesale power market has sufficient liquidity to provide a stable, reliable reference price. A liquid market is one where there are a large numbers of buyers and sellers willing to transact at all times, where transactions do not result in significant change in prices or incur significant transaction costs.
- *The strength of the hedge it offers investors:* CfDs are designed to secure investment in low carbon technology by reducing investment risk through stable, predictable cashflows. Choosing a reference price that enables investors to reduce risk should, in theory, lead to a reduction in the strike price and therefore the cost of subsidy to the Government and ultimately taxpayers. In order for the CfD to provide a strong hedge it must either be a market in which plant can sell their output or a close approximation to the markets where the power is actually sold.

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[2] A PPA is a contract between two parties where the power purchaser buys energy, and sometimes capacity and / or ancillary services from an electricity generator.

[3] For example, see 'The State-of-the-art in short-term prediction of wind power, A literature overview', 2nd Edition, 28th January 2011which concluded: "The current crop of models, typically combining physical and statistical reasoning, is fairly good, although the accuracy is limited by the employed NWP [Numerical Weather Prediction, usually run by meteorological institutes] model.[…] Typical numbers in accuracy are an RMSE [Root Mean Square Error] of about 10-15 per cent of the installed wind power capacity for a 36 hour horizon."

- *Avoiding market distortions and opportunities for gaming:* Given that a potentially large volume of intermittent generation will be subject to a CfD it is possible that the reference market may be distorted. This will depend on the choice of reference market and how the CfD is implemented (i.e. whether contract volume is based either on metered output or availability).

The Government's proposed market reference price for intermittent CfDs is day-head with a choice of either baseload or hourly prices. In the analysis undertaken for DECC, three possible types of day-ahead reference prices are considered:

- Baseload;
- Electricity Forward Agreement ("EFA") blocks; and
- Half-hourly.

Baseload is currently the most liquid market so potentially offers a stable and reliable reference price. However, wind generators are not able to sell their power in only this market due to the significant intra-day variability of wind output. On the other hand, assuming wind generators have the ability to forecast accurately, half-hourly pricing would allow wind generators to match expected output accurately in the reference market but currently is not as liquid as baseload. EFA blocks offer a compromise between these two markets.

6. Factors affecting negative price frequency and severity under an intermittent CfD regime

Intermittent generators selling their power in forward wholesale power markets are able to sell down to a price negative of their support level. This means that their total income remains positive once the support level is taken into account. Negative prices will occur when the price setter in the wholesale market is willing to sell their power at a loss in order to receive the subsidy payment.

Under an intermittent CfD regime this will occur whenever inflexible power generation is greater than the current system demand. The current nuclear fleet is inflexible and unable to respond to price signals by reducing its output in periods of low demand and high wind due to additional costs and risks. Therefore, even if wholesale prices fall below zero it is unlikely that nuclear will be able to avoid these prices unless they persist for very prolonged periods. Overall, there are two principal factors that will increase the likelihood and impact of negative prices:

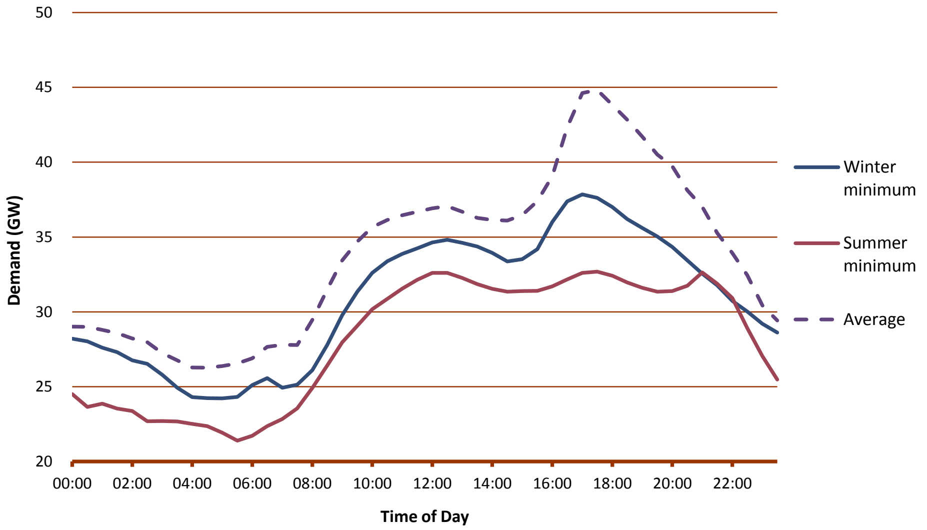
- Minimum system demands
- Increased penetration of low marginal cost plant that will keep running to access support payments.

The following sections look at each of these factors in turn.

6.1. Minimum system demands

6.1.1. Summer minimum, winter minimum and average daily load curves 2011

Figure 6.1: Daily load curves, 2011



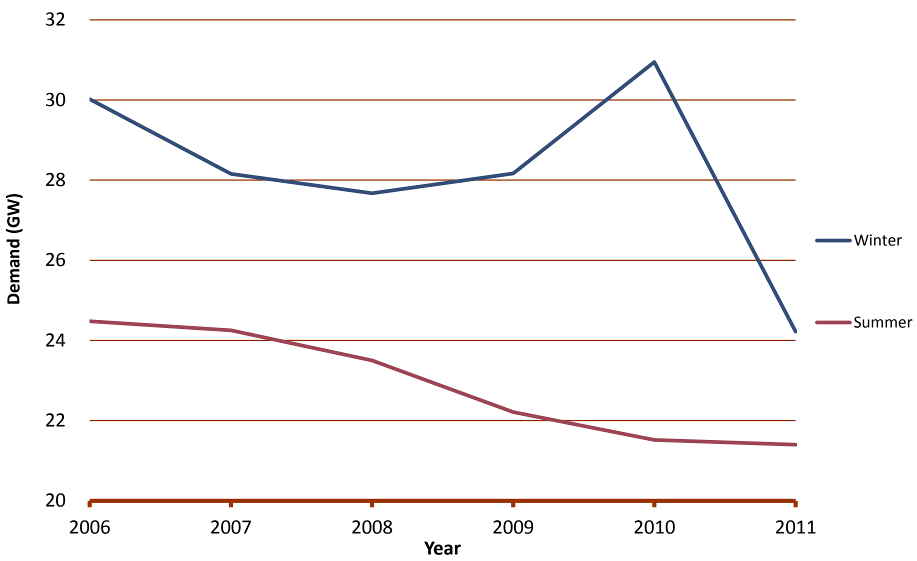
Source: National Grid

Figure 6.1 illustrates the summer minimum, winter minimum and average daily load curves for 2011. The figure clearly highlights that system minimum demands occur during the summer. In 2011, summer minimum demand of around 21.4GW occurs around 5.30am, compared to winter minimum of around 24.3GW for the same time of day.

6.2. Historical minimum system demand 2006 to 2011

6.2.1. Summer minimum demands have been decreasing in recent years

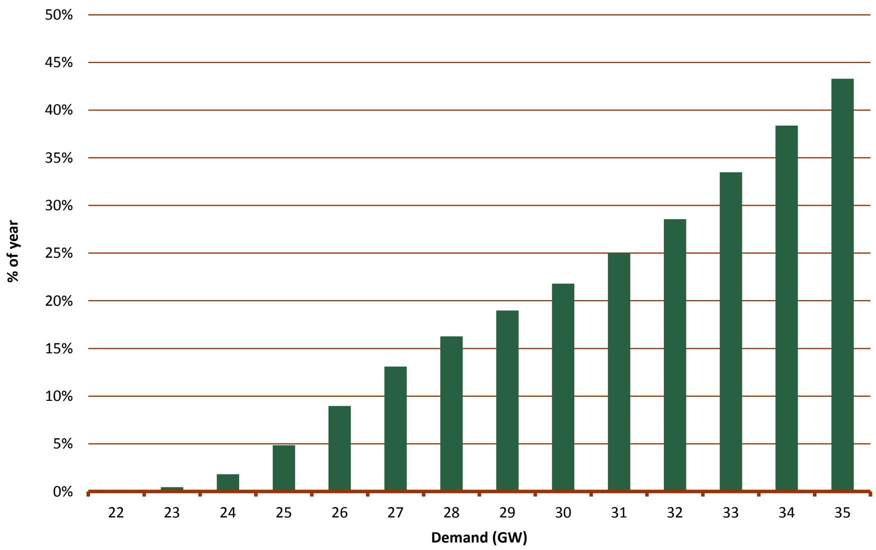
Figure 6.2: Historical minimum demands, 2006 to 2011



Source: National Grid

Figure 6.2 illustrates historical summer minimum demand over the period 2006 to 2011. The chart illustrates a clear downward trend, from 24.5GW in 2006 to around 21.4GW in 2011. The decline reflects decreased economic activity particularly from 2008 onwards, and improvements in energy efficiency by the industrial, commercial and residential sectors.

Figure 6.3: Proportion of time when demand is below a given level, 2011



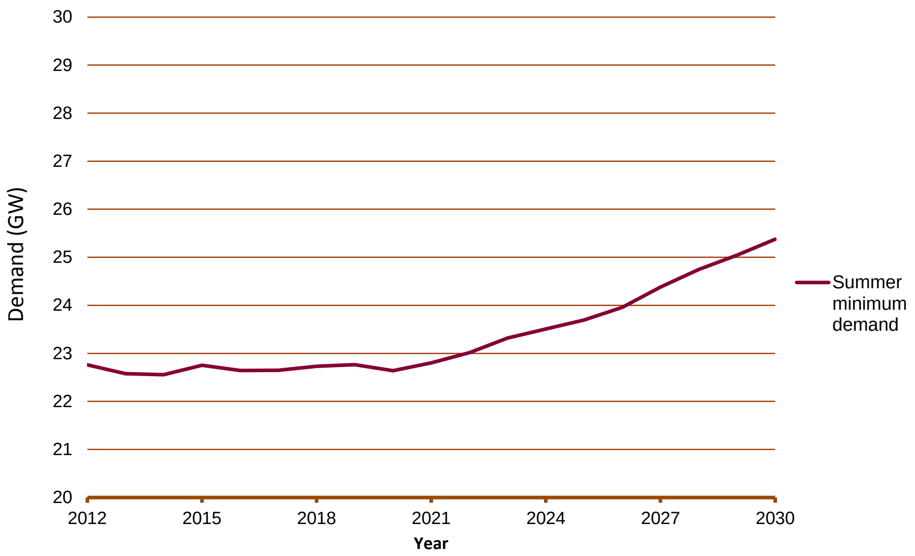
Source: National Grid

There are currently, however, a limited number of periods when these minimum demand occur. Figure 6.3 illustrates there are very few hours when demand is below 25GW.

6.2.2. Future projections of minimum system demands 2012 to 2030

Summer minimum demands are forecast to not change significantly over the period 2012 to 2020, ranging between 22.6GW and 22.8GW reflecting subdued economic activity. Over the 2020s, minimum demands are expected to increase to 25.4GW by 2030, as the economy moves back to a trend rate of growth. The forecasts however do not take into account electrification of motor transportation (which is likely to increase summer minimum demands) and increased energy efficiency (which will have the opposite effect and reduce minimum demands).

Figure 6.4: Forecast summer minimum demand, 2012 to 2030



Source: DECC and National Grid

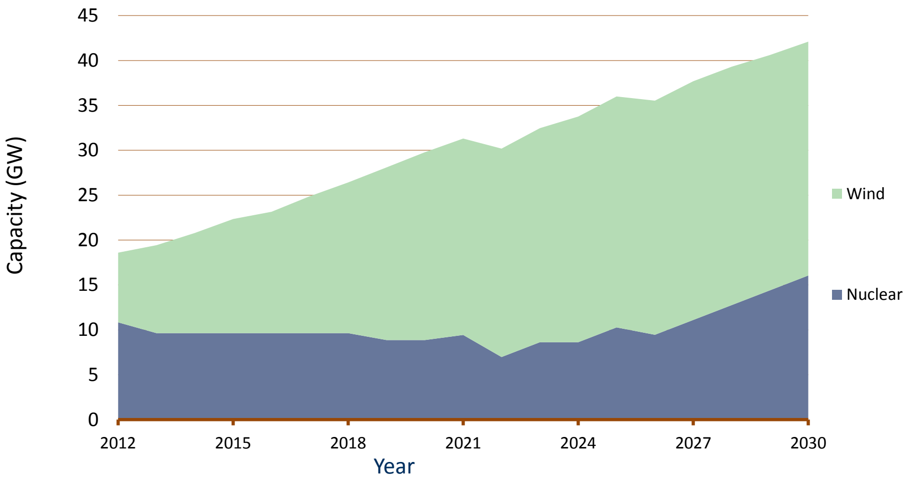
6.3. Increased penetration of low marginal cost plant

6.3.1. Base case nuclear and wind installed capacity 2012 to 2030

As the electricity sector is progressively decarbonised the GB generation fleet will shift from one where thermal generating plant dominates to one where low-carbon generation makes an increasingly significant contribution.

Figure 6.5 illustrates the expected GB nuclear and wind generation deployment from 2012 to 2030 based on DECC's central assumptions. In 2012, there is 10.8GW of nuclear installed capacity and 7.8GW wind generation capacity. By 2030, these are projected to increase to 16.1GW and 24.6GW respectively.

Figure 6.5: Projected installed capacity of inflexible generation, 2012 to 2030

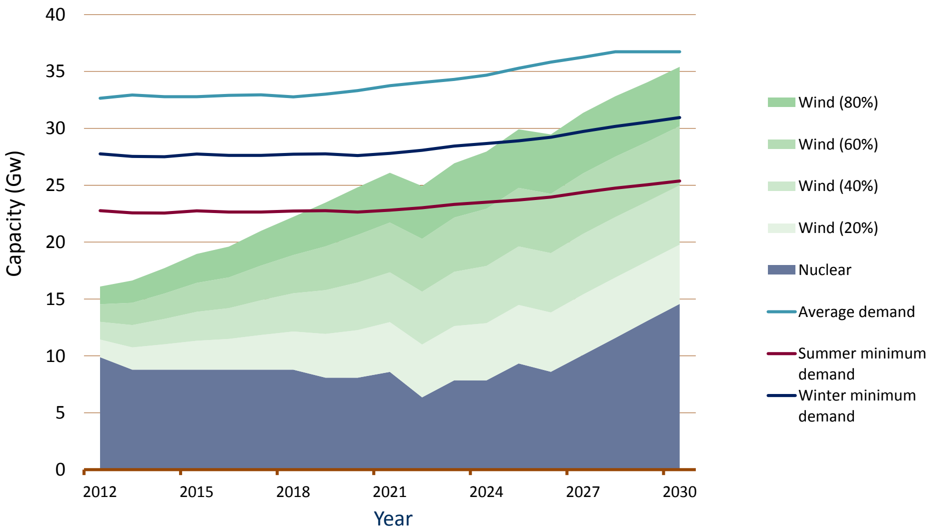


Source: LCP

6.3.2. Varying load factors for wind 2012 to 2030

Actual wind capacity available to generate will depend on wind load factors and how strongly the wind is blowing. Figure 6.6 illustrates the wind capacity available under 20 per cent, 40 per cent, 60 per cent and 80 per cent load factors and, combined with available nuclear capacity, how these compare to projected summer minimum demands (as well as average and peak demands).

Figure 6.6: Projected inflexible generation at different wind load factors, 2012 to 2030



Source: LCP

The figure illustrates that up to around 2017, it is likely that on a system wide level available wind generation can be fully utilised at summer minimum demand, subject to regional constraints and system operator requirements. However, over the period 2018 to 2030, if the period of high wind combines with a period of summer minimum demand, available wind generation may need to be curtailed. In other words, there is a potential overcapacity of inflexible generation at high load factors.

7. Market operation and distortions for intermittent CfD plants

There could be significant distortions for intermittent CfD plants depending on the choice of the day-head reference price i.e. whether baseload, EFA blocks or half-hourly.

Wind under the intermittent CfD regime will receive the difference between the strike price and the reference price. The minimum price they would be able to sell their power and still make a profit will be the negative this difference.

The day-ahead market will be affected when wind plant under a CfD becomes price setting in the reference market or represents a significant proportion of traded volume. Wind will become price setting when expected system demand for less inflexible generation falls below expected wind generation at the day-ahead stage.

In a period where the wind generators become price setting there is potential for them to compete to ensure they receive their policy income. This could be through a CfD or through the existing Renewable Obligation regime (see section 8 for further discussion on CfD interactions with other renewable policies). During such periods there is potential for negative prices with generators willing to pay to be able to generate.

The magnitude of the distortion in the day-ahead market will depend on the reference price chosen.

- *Day-ahead baseload:* In this market it is unlikely that wind plant would ever become price setting.
- *Day-ahead half hourly:* If in any half hour period it is expected that inflexible generation exceeds demand wind plant may become price setting.

The distortion under day-ahead EFA blocks reference price would be some-way between the two.

If CfD wind plants are price setting in the reference market then it is unclear what price will result. This is because the minimum price they are able to sell their power in the market depends on the outturn market prices. In this situation prices could be driven down.

If it is assumed that the day-ahead market is arbitrage free then the time weighted average of the day-ahead half-hourly forwards will be the day-ahead baseload price.

Therefore the change in trading prices in the day-ahead half hourly prices will affect the baseload price and similarly EFA block prices.

8. Intermittent CfD interactions with other renewable policies

The CfD regime will operate alongside the current system of supporting renewables in the UK, the Renewables Obligation ("RO"). Currently, the RO is the main mechanism for supporting large scale deployment of renewable electricity in the UK. The scheme came into effect in England and Wales, and Scotland in 2003 and in Northern Ireland in 2005.

Since its introduction the RO has been subject to various reforms, with the most significant being the introduction of banding in April 2009, where different technologies receive different support in order to incentivise large scale deployment of emerging technologies. The Government is set introduce new regulations this summer setting new bands in law[4].

Renewable Obligation Certificates ("ROC") are certificates issued by Ofgem under the RO for eligible renewable electricity generated within the UK and supplied by a licensed supplier to customers in the UK. In 2010-11, the total ROCs issued was 24.9 million covering 23.2 TWh of renewable generation[5].

Under the current RO scheme an onshore wind generator is issued one ROC per MWh of electricity generated that they could sell into the market for ROCs, as well as selling power. Offshore wind currently receives more generous support, where capacity accredited between 1 April 2010 and 31 March 2014, receives two ROCs per MWh of electricity generated.

Overall, onshore wind is the dominant technology in terms of ROCs issued, with 7.7 million (representing 30.9 per cent of the total) issued in 2010-11. Reflecting the more generous support introduced in 2010-11, there has been a significant increase in the amount of ROCs issued to offshore wind establishing it as the second most popular technology under the RO, with 5.0 million ROCs (representing 20.2 per cent of the total) issued.

Currently, all wind plant coming online before 2014 will be under the RO. However, between 2014 and 2017, all plant coming online will have the choice of becoming either a ROC or a CfD plant.

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[4] http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/renew_obs/renew_obs.aspx

[5] http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Documents1/Renewables%20Obligation%20Annual%20Report%202010-11.pdf

In periods where wind generating plants are sufficient to meet demand, there is a potential for wind plant to compete for the right to generate to receive their subsidies. This materialises in negative prices in the market.

With ROCs, the minimum market price at which they will be willing to generate is equivalent to the negative of the ROC price they expect to achieve.

If at the day-ahead stage there is a period where wind is expected to be the marginal plant then ROC plant and CfD plant will be attempting to sell their power in a market where they are price-setting. In this situation, ROC plants have a fixed and known price whereas the minimum price acceptable to CfD plant will move as the reference price changes. This potential creates a feedback mechanism between the minimum price the CfD plant is willing to generate at and the reference price.

9. Intermittent CfD scenarios

In order to analyse the impact of CfDs on reference and wholesale spot prices and in particular the likelihood and severity of negative prices two generation mix scenarios have been modelled:

- *Base case scenario ("Base case"):* this utilises DECC's central assumptions[6] and assumes RO / CfD support rates are set to bring a relatively lower amount of wind onto the system.
- *High wind installed capacity scenario ("High wind"):* this also utilises DECC's central assumptions but assumes RO / CfD support rates are set to bring on 15.2GW of onshore and 17.6GW of offshore wind capacity onto the system by 2030.

It is noted that future support rates for low carbon technologies are not yet known and deployment will depend not only on the support rates, but a range of uncertain factors, such as technology costs, investor required rates of return and supply chain market dynamics.

The assumptions underpinning the analysis are set out in Appendix B. Wind duration curves and daily load curves are set out in Appendices C and D respectively.

In the following sections, the scenarios and the results of the analysis under the base case and high wind scenarios are presented.

9.1. Base case: DECC's central assumptions

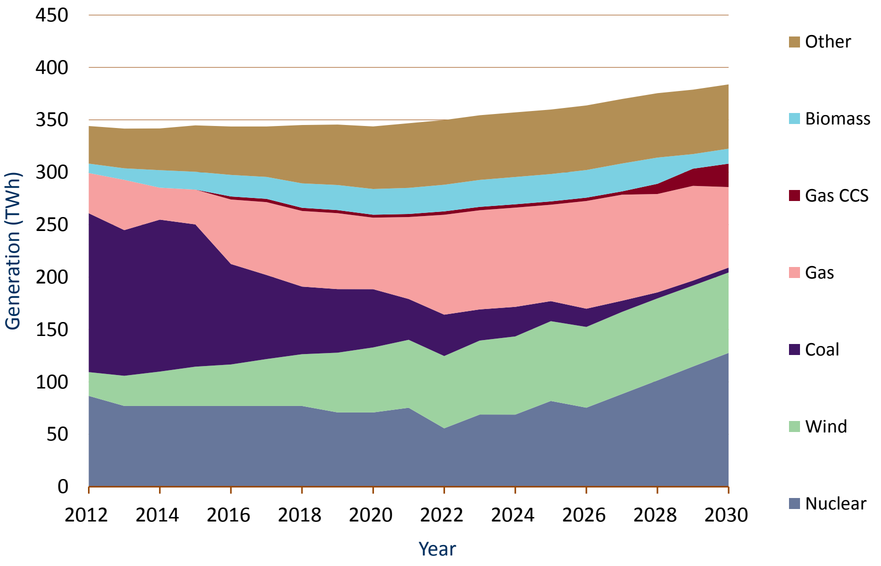
The base case scenario is based on DECC's central assumptions for commodity prices, demand, plant construction and operating costs, and required investor returns. It also

[6] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

assumes RO / CfD support rates are set to bring on a relatively lower amount of onshore and offshore wind onto the system.

In order to determine the type and volume of plant affected by CfDs the strike prices for each generating technology have been set so that the 2030 emissions target is met with the lowest subsidy cost.

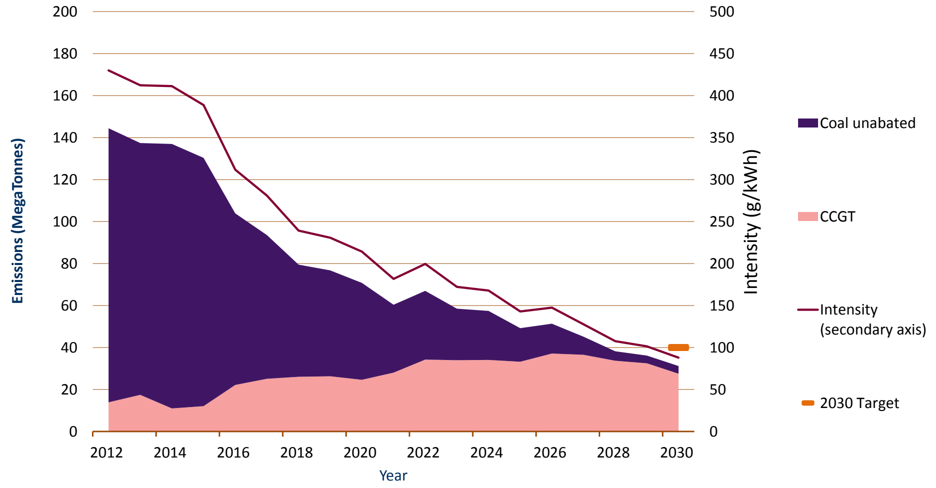
Figure 9.1: Base case – Projected generating mix, 2012 to 2030



Source: LCP

The generation output mix is projected to change dramatically over the period 2012 to 2030. In 2012, according to the modelling, coal plant dominates accounting for around 45 per cent of total generation output, with wind and nuclear accounting for just under a third (32 per cent – 7 per cent wind; 25 per cent nuclear). By 2030, wind and nuclear combined projected share increases to over half (53 per cent – 20 per cent wind; 33 per cent nuclear) of output compared to around 1 per cent for coal. Unabated gas increases from 11 per cent of total generating output in 2012 to 20 per cent in 2030.

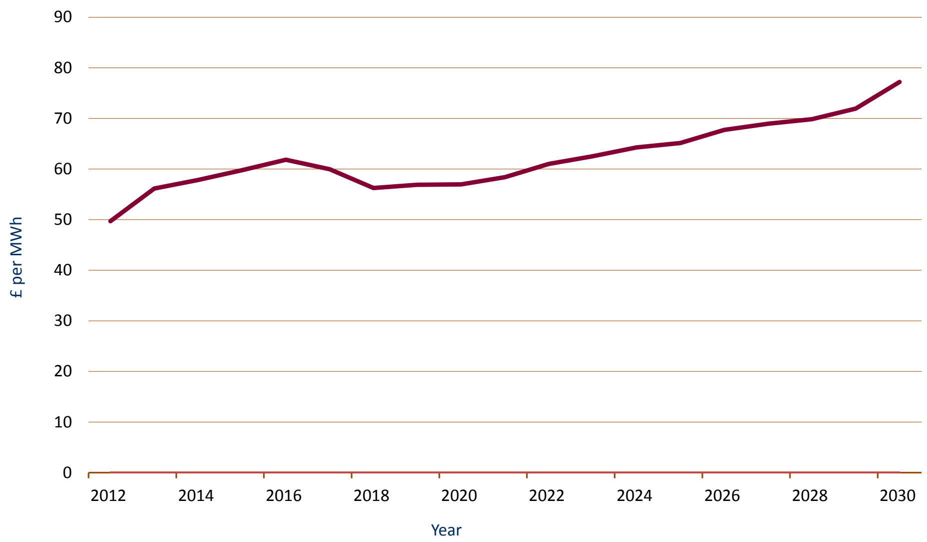
Figure 9.2: Base case – CO_2 emissions for unabated thermal plant, 2012 to 2030



Source: LCP

As electricity is increasingly generated from renewables, carbon capture and storage and nuclear, the carbon intensity of electricity generated will reduce. Emissions from the power sector therefore reduce dramatically from around 430 g/KWh in 2012 to around 214 g/KWh by 2020 (a 50 per cent reduction on 2012 levels) and to 88 g/KWh by 2030 (an 80 per cent reduction on 2012 levels).

Figure 9.3: Base case – Wholesale power prices[7], 2012 to 2030



Source: LCP

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[7] Loss adjusted volume weighted price.

Over the period considered, wholesale power prices are projected to increase from around £50 per MWh in 2012 to just over £77 per MWh in 2030 in real terms.

9.2. Base case: Results

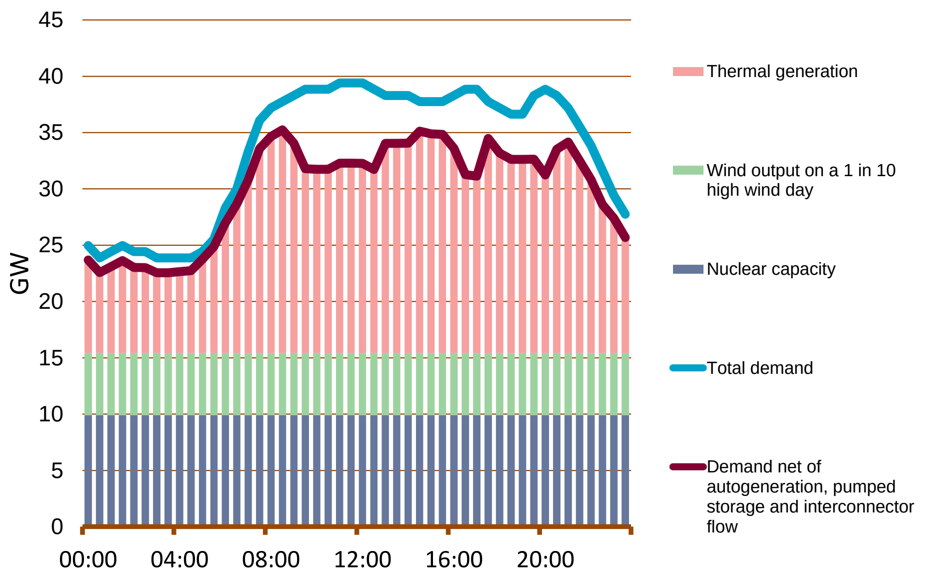
9.2.1. Impact of low demand / high wind periods

Figures 9.4 to 9.7 illustrate the GB generation mix across an example high wind, low demand day under the base case assumptions for 2012, 2020, 2025 and 2030.

The analysis assumes the system operator needs at its disposal back-up reserve generation to reduce the amount of generation output there is on the system in order to ensure that the frequency can be kept within statutory limits. This is referred to as negative reserve or “footroom”. To illustrate the impact of this requirement, it is assumed that around 3GW of footroom is required at all times. It should be noted however that back-up requirements are dynamic and would increase if the largest loss on the system increased and / or wind output to the system increased.

Overall, the figures illustrate that currently the system operator has at its disposal enough back-up flexible thermal generation to ensure that frequency can be kept within statutory limits. However, as wind deployment increases dramatically out to 2030 and with the expected closure of conventional thermal plant over the near term, the system operator will need to take action to curtail wind generation in periods of high wind.

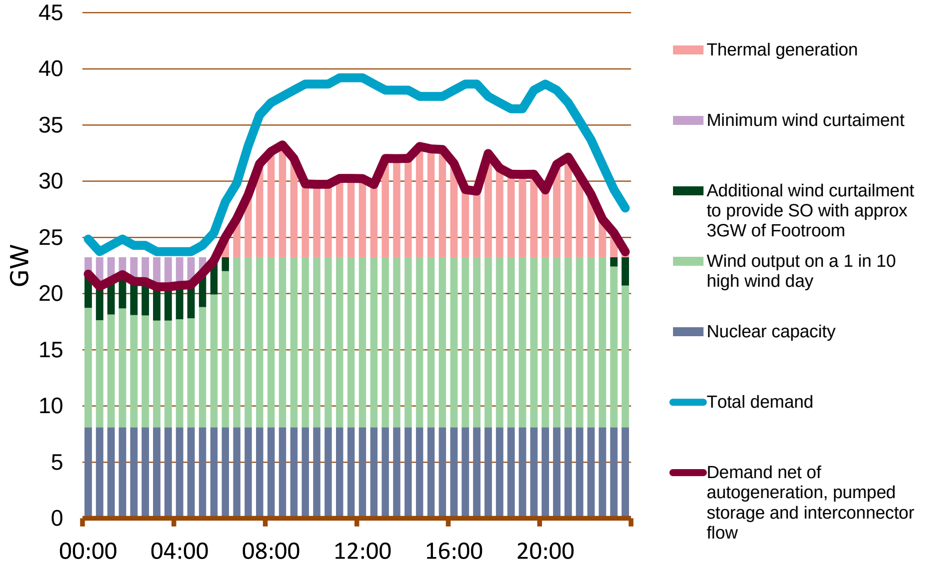
Figure 9.4: Base case – High wind and low demand day, 2012



Source: LCP

In 2012 wind and nuclear generating output combined is not sufficient to meet demand even during the lowest demand periods. This means that conventional thermal plants are required at all times.

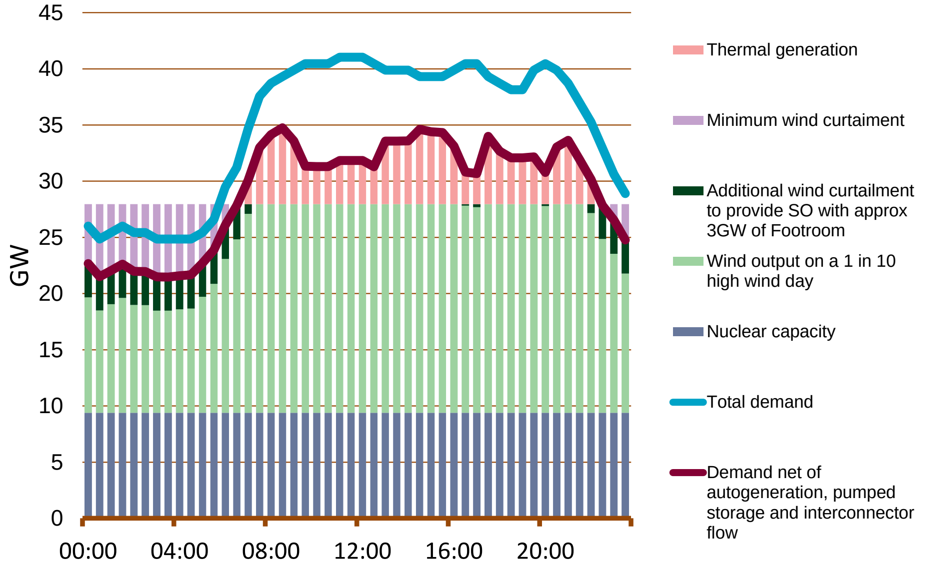
Figure 9.5: Base case – High wind and low demand day, 2020



Source: LCP

In 2020 there are extended periods overnight where nuclear and wind output exceeds net demand. The area in light mauve shows the amount of wind that must be curtailed to avoid generation exceeding demand. There is then further curtailment for periods highlighted in dark green where wind must be curtailed for the system operator to maintain 3GW of footroom.

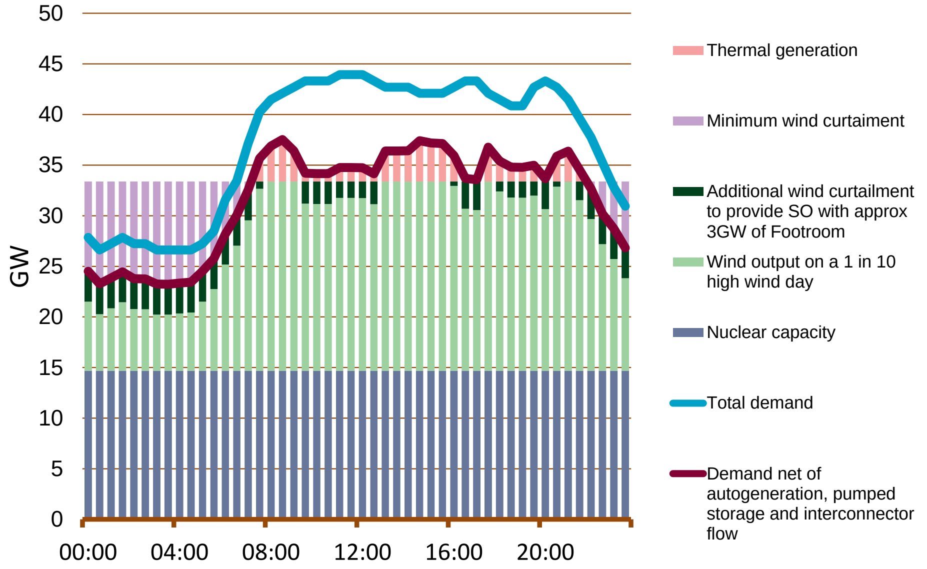
Figure 9.6: Base case – High wind and low demand day, 2025



Source: LCP

Compared to 2020, the amount of nuclear and wind output on the system in 2025 increases and as a result there are extended periods overnight where nuclear and wind output exceeds demand. The area in light mauve shows the amount of wind that must be curtailed to avoid generation exceeding demand. There is then further curtailment for extended periods to meet the footroom requirements of the system operator.

Figure 9.7: Base case – High wind and low demand day, 2030



Source: LCP

In 2030, compared to 2025, the number of periods overnight where nuclear and wind capacity exceeds demand increases. There are also periods throughout the day when further curtailment is required to meet the footroom requirements of the system operator.

9.2.2. Impact on reference and wholesale prices.

The impact of having the following different types of day-ahead reference price was considered:

- Baseload
- EFA blocks
- Half-hourly

To do this, the projected frequency (i.e. how often) and severity (i.e. the extent) of negative prices in the reference and day-ahead half-hourly wholesale spot power market was analysed. Spot prices were analysed because if, at the day-head stage, projections for wind output and demand are accurate then day-ahead half hourly prices are equivalent to the wholesale spot prices for that period.

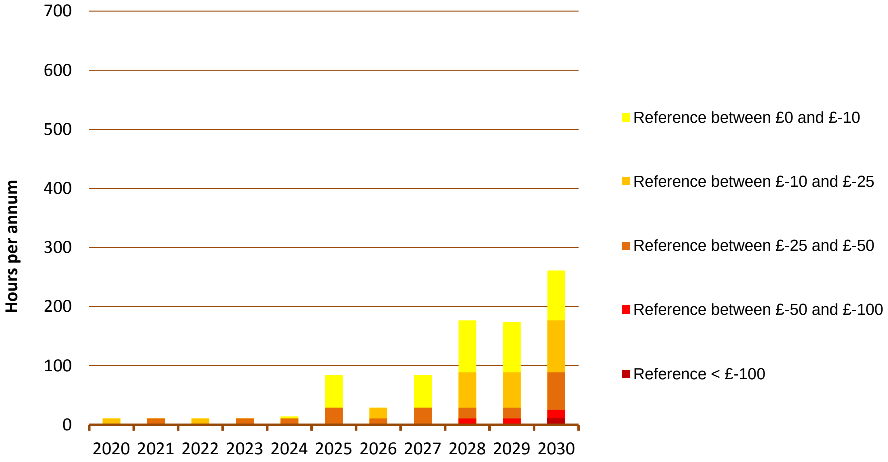
The price in the reference market determines the revenue per MWh that plants under a CfD contract will receive. It therefore also determines the minimum price a plant would be prepared to receive for power. If for example the day-ahead baseload price is £40 per MWh and the strike price for a given plant is £80 per MWh then the minimum price that plant will accept is -£40 per MWh, assuming no running costs. If at the day-ahead stage there is any half-hour period where that plant is expected to be the marginal plant then it is assumed that the day-ahead market for that half hour period will settle at -£40 per MWh.

Figures 9.8 to 9.12 illustrate the projected impacts on reference and wholesale prices over the period 2012 to 2030. The bar charts illustrate both how often prices are negative (i.e. the total number of hours per annum less than £0) and the severity of the impact (e.g. less £0 but greater than or equal to minus £10, etc.).

Figures 9.8, 9.10 and 9.12 show the price in the reference market under Baseload, EFA and Half-hourly prices. The price in this market determines the CfD revenue that plant will receive.

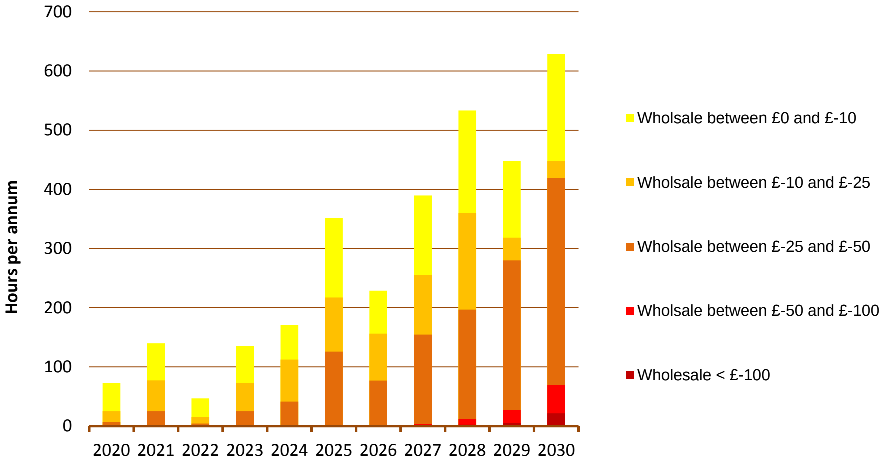
Given the reference prices, figures 9.9 and 9.11 shows the price in the day-ahead half-hourly market under the Baseload and EFA reference prices. This is the price in the half-hourly market given the revenue being paid from the CfD. The different reference prices lead to different severities of negative prices but there is little impact on the frequency. There is no equivalent to 9.9 and 9.11 for half-hourly reference prices as the reference market is the half-hourly market.

Figure 9.8: Base case – Day-ahead baseload reference price, 2020 to 2030



Source: LCP

Figure 9.9: Base case – Day-ahead half-hourly spot price under day-ahead baseload reference price, 2020 to 2030



Source: LCP

Figure 9.8 illustrates negative baseload reference prices are unlikely to become a major issue until the mid-2020s.

Between 2020 and 2024, there is a possibility of around 1 day each year where reference prices are projected to be negative. In 2025, this increases to around 4 days and this is projected to increase to 11 days by 2030, representing around 3 per cent of total days in the year.

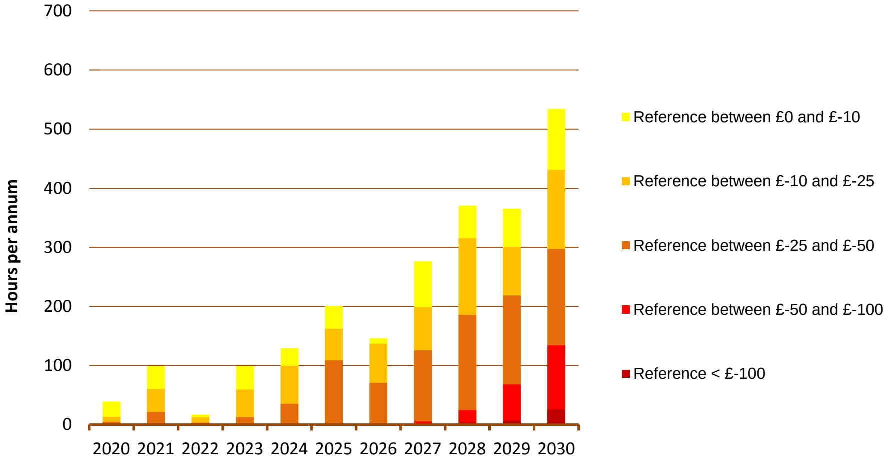
In terms of severity, only in 2028, 2029 and 2030 are there some limited periods where the reference price is less than minus £50 but greater than or equal to minus £100 (around 1 day each year in 2028, 2029 and 2030). Only in 2030 are reference prices projected to drop below £100 (for around 1 day).

However, wind under the CfD will receive the difference between the strike price (i.e. set in the day-ahead half-hourly wholesale spot power market) and the reference price (i.e. the day-ahead baseload price).

Throughout the 2020s, the number of hours the day-head half-hourly spot power market is projected to be negative is expected to increase from around 73 hours in 2020, to 362 hours in 2025, reaching around 650 hours in 2030. In 2030, this represents around 7 per cent of total hours in the year.

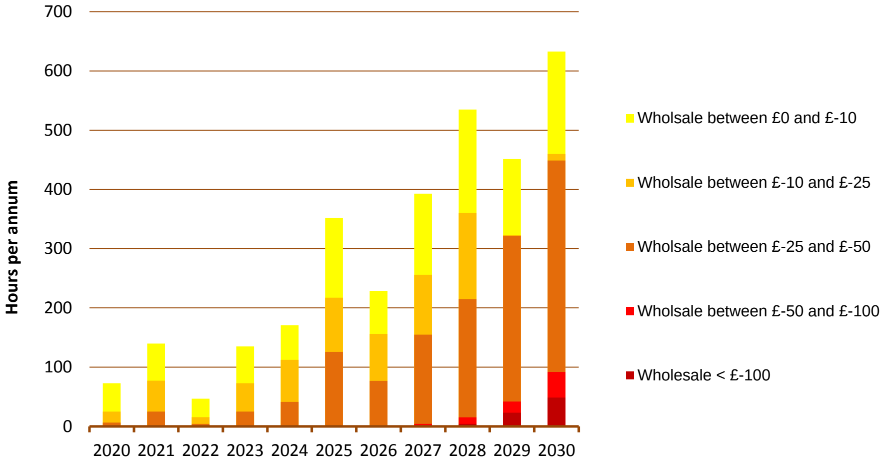
In terms of severity, only in 2025 and beyond are spot prices less than minus £50 but greater than or equal to £100 and then only greater than 2 hours each year from 2028 onwards (10 hours in 2028, 21 hours in 2029 and 53 hours in 2030). Only from 2028 to 2030 are spot prices projected to below £100 (for 2 hours in 2028, 8 hours in 2029 and 22 hours in 2030).

Figure 9.10: Base case – Day-ahead EFA blocks reference price, 2020 to 2030



Source: LCP

Figure 9.11: Base case – Day-ahead half-hourly spot price under day-ahead EFA blocks reference price, 2020 to 2030



Source: LCP

Figure 9.10 illustrates negative EFA block day-ahead reference prices occur more frequently than baseload day-ahead reference prices over the whole of the 2020s.

Between 2020 and 2025, the number of EFA blocks where reference prices are negative is projected to increase from around 10 in 2020 to around 55 in 2025. Beyond 2025, the number of EFA blocks is projected to steadily increase year-on-year to around 142 in 2030, representing around 6 per cent of total EFA blocks in the year.

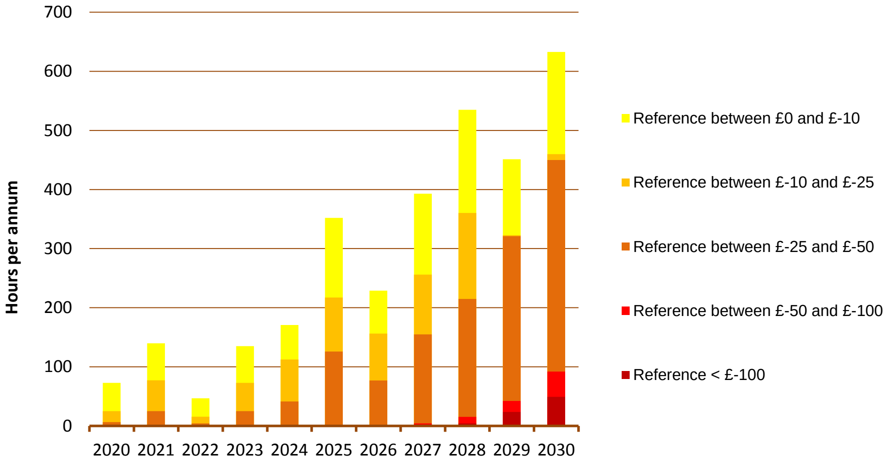
In terms of severity, only in 2025 and 2027 and beyond are there periods where the reference price is less minus £50 but greater than or equal to minus £100 (around 1 EFA block in 2025 and 2027, 5 EFA blocks in 2028, around 18 EFA blocks in 2029 and around 28 in 2030). In 2028 to 2030 there are periods where reference prices projected to drop below £100.

However, if the wind generator is contracted on an EFA block reference price basis at the day-ahead stage this results in the wholesale market distortions illustrated in figure 9.11. Wind under the CfD will receive the difference between the strike price and the reference price (i.e. the day-ahead EFA block price).

Throughout the 2020s, the number of hours the day-head half-hourly spot power market is projected to be negative under an EFA block reference price is expected to increase from around 73 hours in 2020, to 362 hours in 2025, reaching around 654 hours in 2030. In 2030, this represents around 7 per cent of total hours in the year.

In terms of severity, only in 2025 and beyond are spot prices less than minus £50 but greater than or equal to £100 and then only greater than 2 hours each year from 2027 onwards (4 hours in 2027, 11 hours in 2028, 21 hours in 2029 and 46 hours in 2030). Only from 2027 onwards spot prices projected to below £100 (for 1 hour in 2027, 4 hours in 2028, 23 hours in 2029 and 49 hours in 2030).

Figure 9.12: Base case – Day-ahead half-hourly reference price = Day-ahead half-hourly spot, 2020 to 2030



Source: LCP

Figure 9.12 illustrates negative half-hourly reference prices are more prevalent than under baseload or EFA block reference prices.

Between 2020 and 2025, the number of hours where reference prices are negative is projected to increase from around 73 hours in 2020 to around 362 hours in 2025. Beyond 2025, the number of hours is projected to steadily increase year-on-year to around 654 hours in 2030, representing around 7 per cent of total hours in the year.

In terms of severity, only in 2025 and beyond are there periods where the reference price is less minus £50 but greater than or equal to minus £100 (1 hour in 2025, less than 1 hour in 2026, 4 hours in 2027, 11 hours in 2028, 21 hours in 2029 and 45 hours in 2030). In 2027 to 2030 there are periods where reference prices projected to drop below £100 (1 hour in 2027, 4 hours in 2028, 24 hours in 2029 and 49 hours in 2030).

9.2.3. Potential increased revenue for energy storage

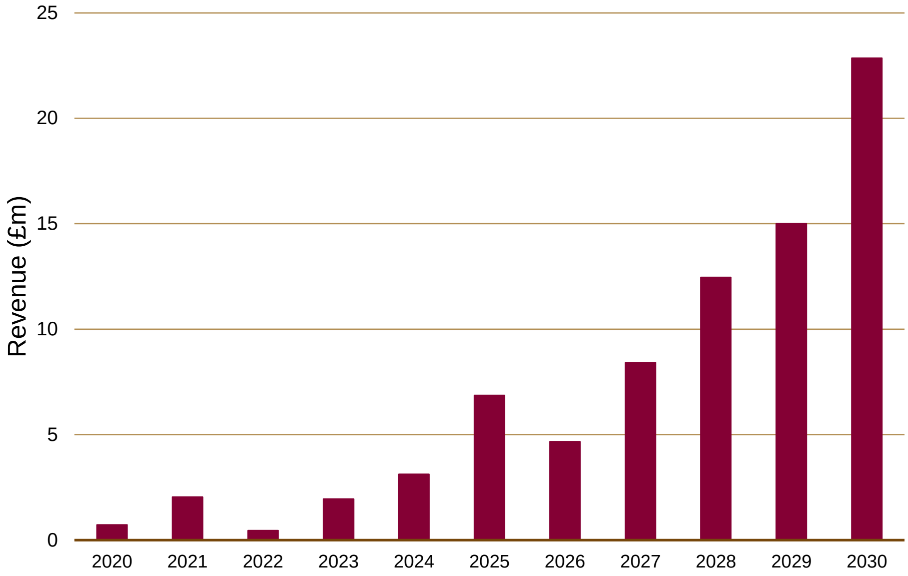
The frequency and severity of negative prices shown in section 9.2.2 could act as a significant incentive for energy storage, whereby consumers create demand. To incentivise energy storage consumers would receive a rebate for consuming electricity during negative price periods.

Energy storage during these high wind and low demand periods would attempt to increase system load to maintain network integrity.

Figure 9.13 illustrates the additional revenue that 1GW of energy storage would be able to receive as a result of the negative prices caused by the intermittent CfDs under the worst case scenario. Clearly, the incentives for energy storage increase significantly between 2025 and 2030, as the frequency and severity of negative prices increases.

However, if incentivising energy storage is the aim then this would ideally be targeted by incentivising technologies that are able to reduce the generation requirement at peak. The revenue below will be providing an incentive for increased demand at the off-peak period which may provide little benefit in-terms of peak load reduction.

Figure 9.13: Potential energy storage revenue, £m per GW, 2020 to 2030

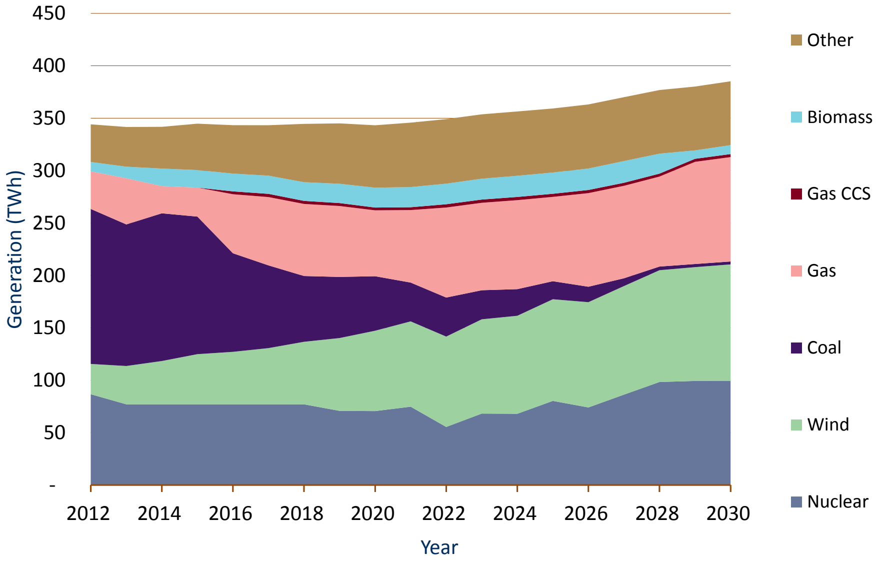


Source: LCP

9.3. High wind scenario

The high wind scenario uses DECC central assumptions but also assumes RO / CfD support rates are set to bring on relatively higher amount of onshore and offshore wind onto the system. As a result, 15.2GW of onshore and 17.6GW of offshore wind is forced onto the system, with capacity installed in line with ARUP build rates[8]. Other types of generating plant are assumed to be built on the same basis as the base case scenario.

Figure 9.14: High wind – Projected generating mix, 2012 to 2030



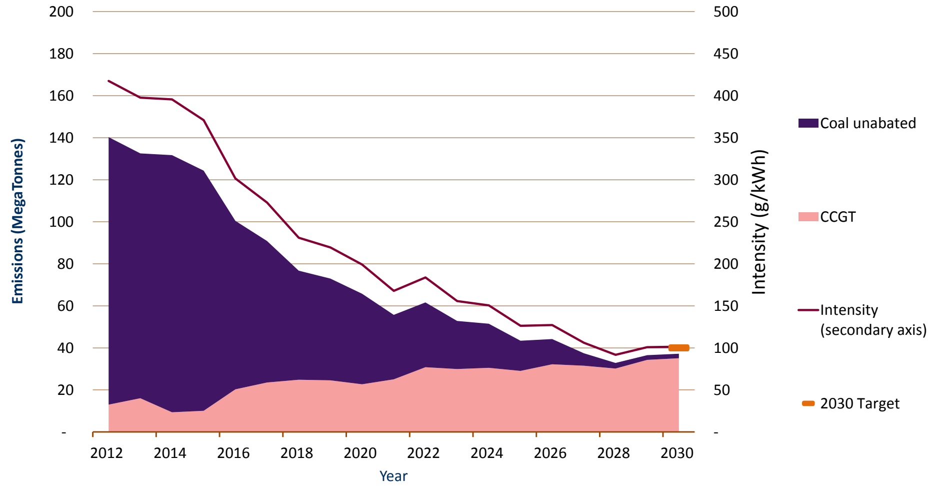
Source: LCP

As with the base case scenario, the generation output mix is projected to change dramatically over the period 2012 to 2030 albeit with a greater contribution from wind (both onshore and offshore).

In 2012, coal plant dominates accounting for around 41 per cent of total generation output, with wind and nuclear accounting for over a third (36 per cent). By 2030, wind and nuclear combined projected share increases to over half (58 per cent) of output compared to less than 1 per cent for coal. Unabated gas increases from 10 per cent of total generating output in 2012 to 23 per cent in 2030.

[8] http://www.decc.gov.uk/assets/decc/11/consultation/ro-banding/3237-cons-ro-banding-arup-report.pdf

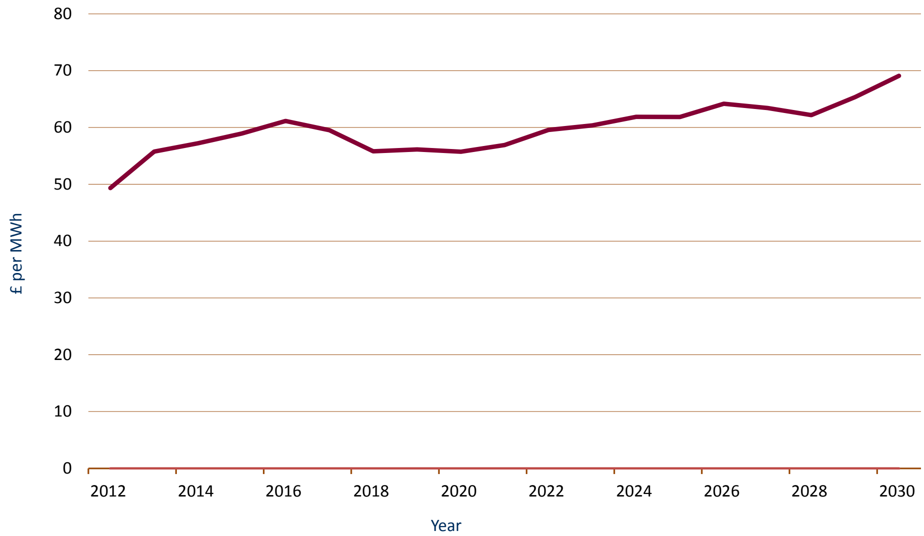
Figure 9.15: High wind – CO_2 emissions for unabated thermal plant, 2012 to 2030



Source: LCP

As electricity is increasingly generated from renewables and nuclear, the carbon intensity of electricity generated will reduce. By forcing wind onto system, emissions are marginally lower initially although with no gas CCS coming online in the late 2020s, emissions in 2030 are marginally higher (although below the 2030 target). Emissions from the power sector therefore reduce dramatically from around 399 g/KWh in 2012 to around 178 g/KWh by 2020 (a 55 per cent reduction on 2012 levels) and to 91 g/KWh by 2030 (a 77 per cent reduction on 2012 levels).

Figure 9.16: High wind – Wholesale power prices, 2012 to 2030



Source: LCP

Over 2012 to 2030, wholesale prices are projected to increase from around 49 per MWh in 2012 to around £65 per MWh in 2030. In 2030 this is around £12 per MWh lower than the price projected under the base case scenario, reflecting the higher level of installed wind capacity on the system.

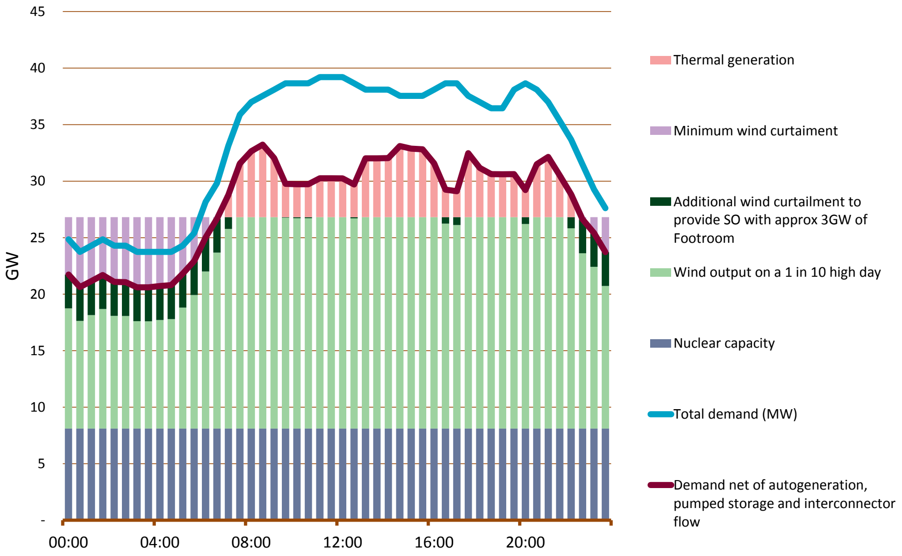
9.4. High wind scenario: Results

9.4.1. Impact of low demand / high wind periods

Figures 9.17 to 9.19 illustrate the GB generation mix across an example high wind, low demand day under the high wind scenario assumptions for 2020, 2025 and 2030.

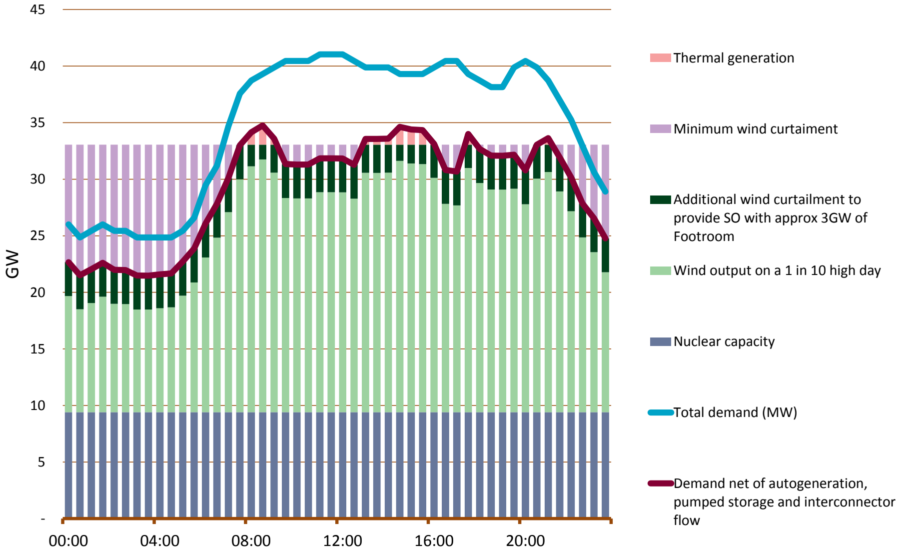
The figures illustrate that with increased wind deployment when compared to the base scenario, the system operator will need to take action overnight and during some daytime periods in 2020 and across all periods in 2025 and 2030.

Figure 9.17: High wind – High wind and low demand day, 2020



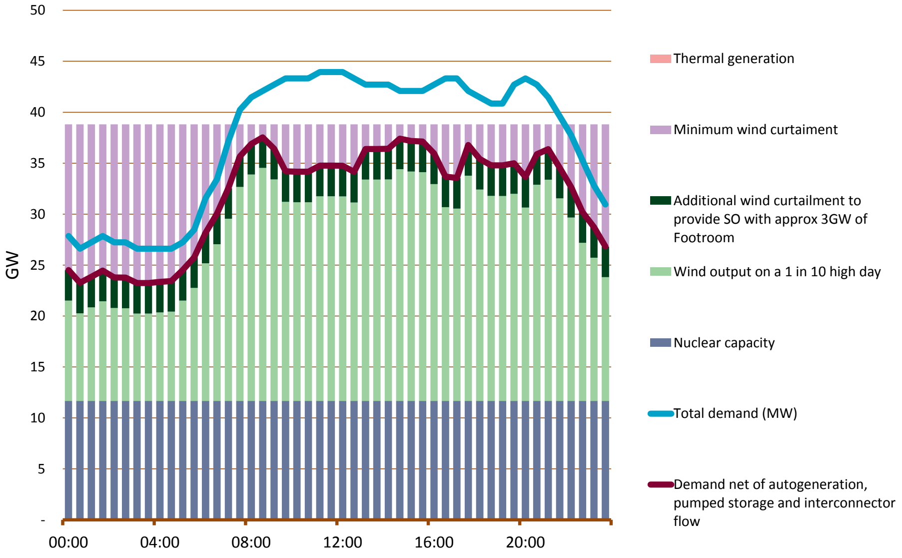
Source: LCP

Figure 9.18: High wind – High wind and low demand day, 2025



Source: LCP

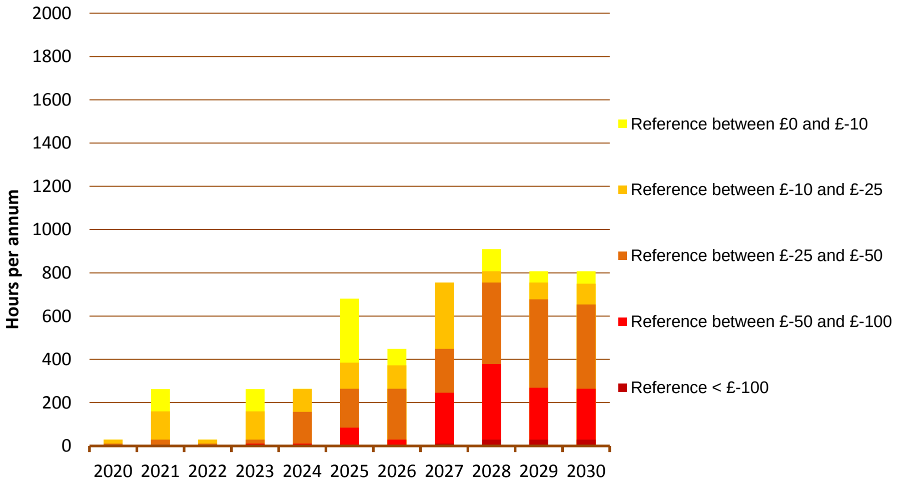
Figure 9.19: High wind – High wind and low demand day, 2030



Source: LCP

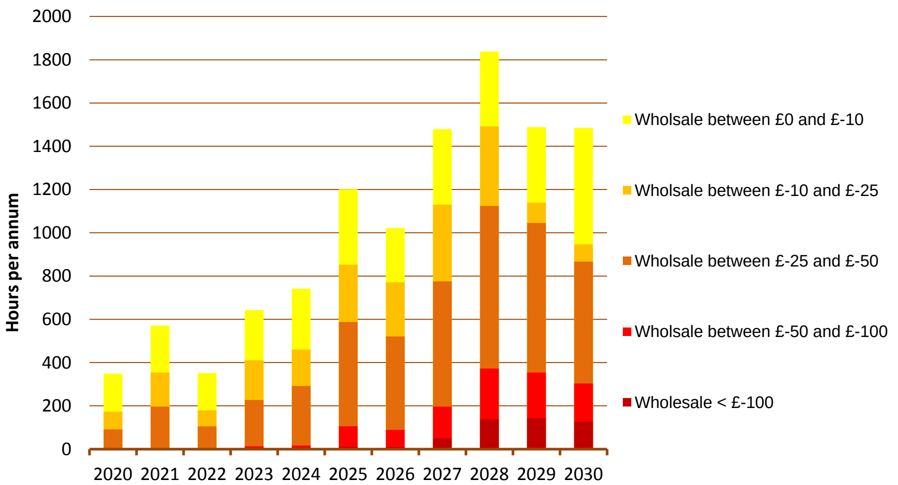
9.4.2. Impact on reference and wholesale prices

Figure 9.20: High wind – Day-head baseload reference price, 2020 to 2030



Source: LCP

Figure 9.21: High wind – Day-ahead half-hourly spot price under day-ahead baseload reference price, 2020 to 2030



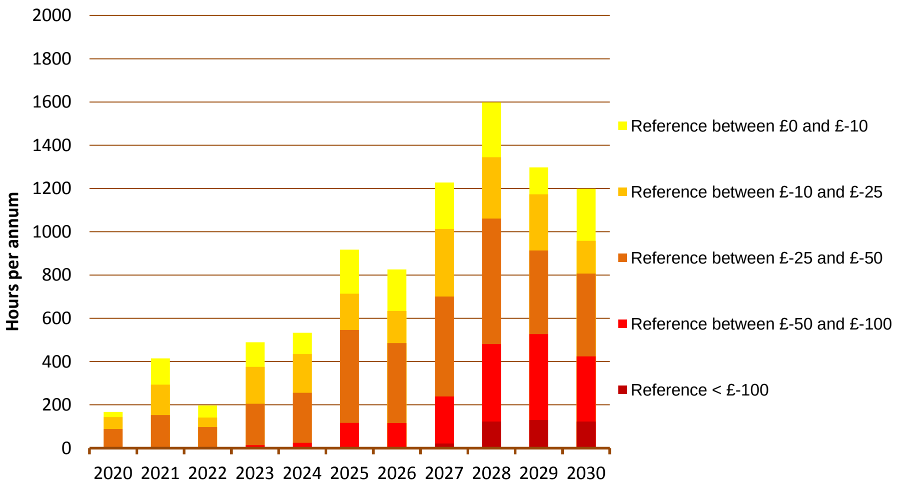
Source: LCP

Figure 9.20 illustrates, when compared to the base case (see figure 9.8), negative baseload reference prices are much more of an issue in the 2020s under the high wind scenario. From 2020 to 2024 there are at most 10 days of negative baseload prices.

Negative prices peak at 35 days per annum in 2028, equivalent to 10 per cent of total days. The fall in frequency of negative prices from 2028 to 2030 reflects there is little additional investment in wind and nuclear generation over this period but demand continues to increase.

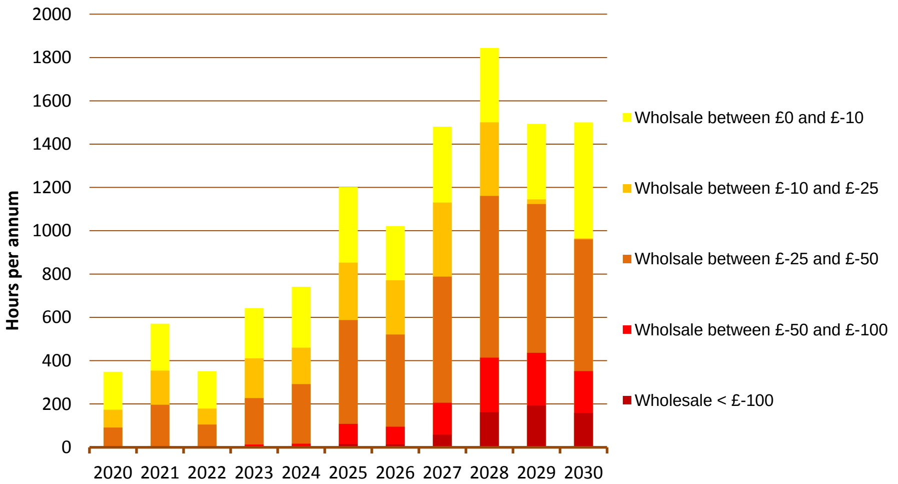
Figure 9.21 shows that the frequency of negative price in the half-hourly market is considerably higher in the high wind scenario when compared to the base case (see figure 9.9). This peaks in 2028 with 1800 negative price hours, equivalent to 20 per cent of total hours.

Figure 9.22: High wind – Day-ahead EFA blocks reference price, 2020 to 2030



Source: LCP

Figure 9.23: High wind – Day-ahead half-hourly spot price under day-ahead EFA blocks reference price, 2020 to 2030

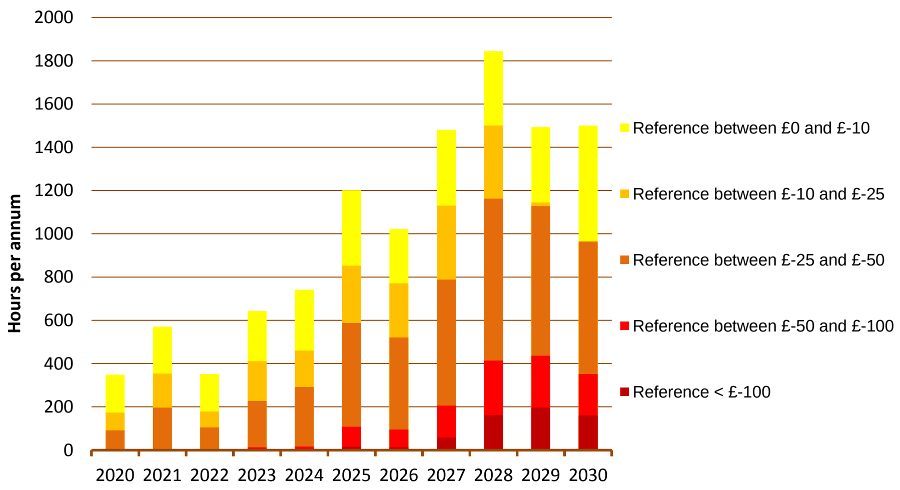


Source: LCP

Figure 9.22 shows how the EFA blocks reference market experiences considerably higher frequencies of negative prices in the high wind scenario when compared to the base case (see figure 9.10). In 2028 this is around 1800 hours, equivalent to 20 per cent of the year.

Throughout the 2020s, the number of hours the day-head half-hourly spot power market is projected to be negative under an EFA block reference price is expected to increase from around 300 hours in 2020, to 1200 hours in 2025, reaching around 1800 hours in 2028. In 2028, this represents around 20 per cent per cent of total hours in the year.

Figure 9.24: High wind – Day-ahead half-hourly reference price = Day-ahead half-hourly price, 2020 to 2030



Source: LCP

Figure 9.24 illustrates negative half-hourly reference prices are more prevalent than the base case (see figure 9.12).

The number of hours where the half-hourly market prices are negative is projected to reach over 700 hours in 2024. This increases to 1800 hours in 2028, again representing around 20 per cent of total hours in the year.

10. Sensitivity of the intermittent CfD base case results

There are a number of uncertainties associated with the analysis:

- *The availability and flexibility of nuclear generation.*

  There is a considerable amount of uncertainty regarding the volume of new nuclear capacity that may come on line before 2030. There is also uncertainty on when existing plant may close.

The current nuclear fleet is inflexible and the analysis assumes that new nuclear will also be unable to respond to negative prices. However, if future nuclear can offer a degree of flexibility then negative prices would be less frequent.

- *The availability and flexibility of interconnection.*

  Interconnection has the potential to reduce the frequency of negative prices if inflexible generation can be exported at times of low demand. This will depend on investment in new interconnection and prices in the connected market(s).

- *The availability of storage technologies.*

  Currently pumped storage has the ability to shift inflexible generation away from low demand periods. If new technologies allow an increased amount of generation to be shifted away from low demand periods this could significantly reduce the frequency of negative prices.

- *The volume of demand side response.*

  Increase deployment of demand side response will also have the ability to shift demand away from high to low demand periods, reducing the frequency of negative prices.

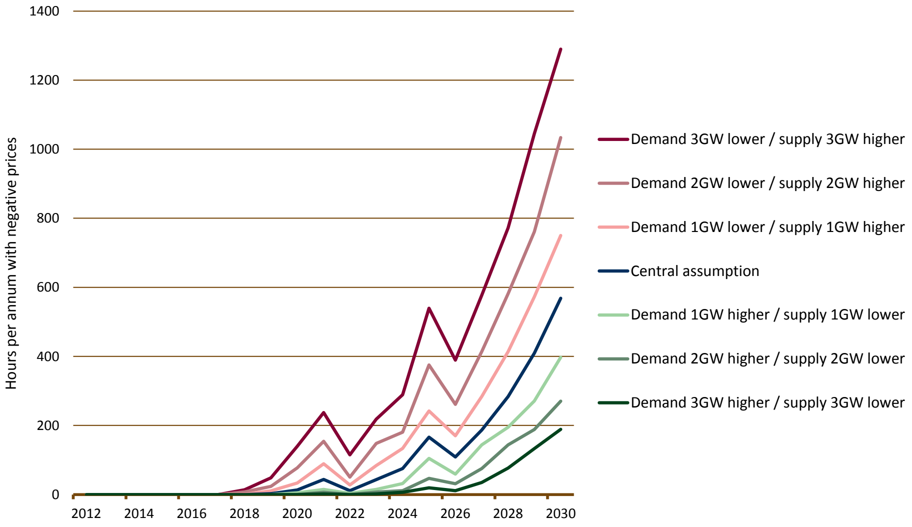
- *The volume and flexibility of embedded generation.*

  There is an increasing amount of embedded generation on the system that may not respond to price. An increase in the volume of this will increase the frequency of negative prices.

Each of these uncertainties has the ability to either narrow or widen between low demand levels and the level of inflexible generation.

To illustrate the sensitivity of the base case day-ahead half-hourly spot price results, figure 10.1 shows how the number of negative price hours is impacted by the level of demand or supply adjusted by minus 3GW, minus 2GW and minus1GW but also plus 1GW, plus 2GW and plus 3GW. The effect of an increase in demand is equivalent to a decrease in inflexible supply.

Figure 10.1: Sensitivity of base case day-ahead half-hourly spot price results



Source: LCP

Overall, the figure illustrates that relatively small changes can have significant impacts on the modelling results, with negative price distortion more sensitive to reducing demands / increasing inflexible supply than rising demands / lower inflexible supply.

For example, when the level of demand is adjusted downwards by 3GW this more than doubles the incidence of negative prices; whereas adjusting demand by the same magnitude in the other direction reduces the incidence of negative prices by around two-thirds

An example of increased level of inflexible supply would be if there was an additional 3GW of nuclear capacity. This would also more than double the incidence of negative prices. If nuclear capacity was 3GW lower though this would reduce the incidence of negative prices by two-thirds.

11. Mitigating policy options for intermittent CfDs and conclusion

The purpose of the modelling and analysis that has been undertaken for DECC is to help policy makers understand which reference price to use and how contract volume should be determined.

The intermittent CfD analysis shows that negative reference and wholesale prices are unlikely to become an issue until the 2020s. The magnitude of the distortion in the 2020s does depend on the day-head reference price chosen with the reference price market distortion least for baseload and highest for half-hourly. A higher rate of renewables (i.e. wind) deployment and penetration also has a material impact, increasing the magnitude of the distortion significantly.

There are, however, alternatives to metered output which mitigate the distortions identified. The first option is to have payments based on availability, where the CfD generator only receives the support if they are available to generate. The second option is to cap the support at the strike price, where the CfD plant does not generate if prices drop below negative the strike price. Table 11.1 briefly sets out the advantages and disadvantages of these two approaches.

Table 11.1: Policy options for intermittent CfDs

	Payments based on availability	Capping the support at the strike price
Advantages	▪ Reduces the cost to the system operator to constrain wind	▪ Intermittent CfD plant will not generate if prices drop below negative of strike price
Disadvantages	▪ Practically difficult to measure theoretical output, especially simulating when cut-off is likely ▪ Costs of monitoring equipment and administration	▪ ROC plant gain preference over CfD plant ▪ Possible increase to strike prices if investors perceive a high frequency of negative prices ▪ System operator still required to compensate for lost output when they need to constrain plants covered by CfD

Source: LCP

12. Conclusions

Overall, for intermittent CfDs our analysis highlights that the choice of reference price impacts the frequency and severity of negative prices although these are unlikely to be an issue until in the 2020s. During the 2020s the reference price market distortion is least for baseload and highest for half-hourly. A higher rate of renewables deployment and penetration increases the magnitude of the distortion significantly. There are policy options to mitigate these impacts, each with their own distinct advantages and disadvantages.

The analysis presented in this report is sensitive to relatively small changes in the assumptions which potentially having significant impacts on the results. Our sensitivity analysis highlights the negative price distortion is more sensitive to reducing demands / increasing inflexible supply than rising demands / lower inflexible supply.

ANALYSIS OF BASELOAD CFDS

The following sections outline:

- The specific characteristics of baseload generation and the incentives that result due to these characteristics.
- The factors that will need to be taken to account for contracted volume for baseload CfDs.
- The potential distortions for baseload CfD plants.
- Baseload CfD interactions with other renewable policies.
- The scenarios and analysis that has been undertaken for baseload CfDs.
- Potential more extreme long-term distortions under baseload CfDs.
- The long-term possibility of negative prices under baseload CfDs.
- Conclusions that can be drawn from the modelling and analysis.

The next section outlines the issues for baseload generators and the incentives that result.

13. Issues for baseload generators

For year-ahead baseload CfDs there are three low-carbon technology types that were considered[9]:

- Nuclear;
- Biomass; and
- Gas Carbon Capture and Storage ("Gas CCS").

Inflexible baseload generation has the following specific characteristics:

- Stable and constant level of output at high load factors, which has a very limited ability to vary at short notice to match demand.
- Typically runs throughout the year except for repairs and scheduled maintenance.
- Relatively straightforward to forecast output accurately.

Nuclear is referred to as "baseload" plant.

Flexible mid-merit generation has the following specific characteristics:

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[9] Other renewable energy sources can also provide baseload power.

- Capable of repeated, reliable starts to match seasonal demand.
- Tends to be operational during the winter period.

Biomass and gas CCS do have some ability to alter their output, particularly if not operating at maximum load factors, and can therefore to some extent respond to changes in system demand. However, gas CCS and biomass sit below conventional thermal ("peaking") generating plant with high short-run marginal costs. Biomass and gas CCS are therefore referred to as "mid-merit" plant.

Due to the predictability ahead of dispatch, baseload and mid-merit generators have strong incentives to sell ahead of delivery.

14. Firm volume versus metered output

The Government is considering two options for determining the volume of electricity under the baseload CfD for which the generator can receive support:

- *Metered output:* This bases the contract volume on the metered output of the plant.
- *Firm volume:* This bases the contract on a pre-agreed firm volume.

Each of these approaches has advantages and disadvantages:

- Under the metered output approach, there are concerns that the generator's dispatch decisions could be distorted, leading to the system not being economically efficient.
- Under the firm volume approach there are concerns that certain plant may be supported when they are not generating:
  - If the strike price is higher than the reference price, the generator could receive payments even if it is not producing electricity; or
  - If the strike price is below the reference price, the generator may not be able to access market prices to hedge against payments.

The hedge it offers investors

CfDs are designed to reduce the risk faced by investors by providing a stable income stream over time. The strength of the hedge it offers investors will vary depending on whether metered output or firm volume is chosen.

Broadly speaking, the CfD is designed to give generators a fixed revenue per MWh equal to the strike price. This will occur if:

- *The plant's actual output volume is equal to the contracted volume.*

This will be the case under a metered output contract. With a firm volume contract this is unlikely to be true and will vary based on the volume contract and any outages the plant may have.

- *The average price achieved by a plant per MWh is equal to the reference price of the contract.*

  This is unlikely to be true as the year-ahead reference is likely to be different from outturn prices. Also the price a plant is able to achieve will depend on exactly which periods the plant is generating and the market in which the plant is selling its power.

The importance of any imbalance will depend on the difference between the reference price and the strike price.

15. Market operation and distortions under baseload CfDs with metered output

The following factors could affect the likelihood of market distortion:

- The capacity of mid-merit plant contracted under a CfD;
- The position of the CfD plant in the merit order; and
- The differential between the strike price and reference price.

The next sections look at each of these factors in turn.

15.1. CfD mid-merit plant capacity

The likelihood of market distortion will be affected by the amount of CfD mid-merit plant capacity.

CCS technology captures carbon dioxide from fossil fuel power stations (i.e. coal and gas). The carbon dioxide is then transported via pipeline and stored offshore in deep underground structures. CCS has yet to be proven as a commercially viable energy technology although there is an expectation that a demonstration plant will become operational in 2016 with further plant developed from 2028 onwards. However, this means there are likely to be relatively low levels of CCS deployment over the period considered.

In comparison, electricity generated from biomass is a relatively more established technology, which is now past the demonstration phase for dedicated biomass generating plant, although this tends to operate on a relatively small scale. The amount of installed biomass capacity is likely to be deployed at higher levels than CCS, at least initially, given the technology is proven and commercially viable.

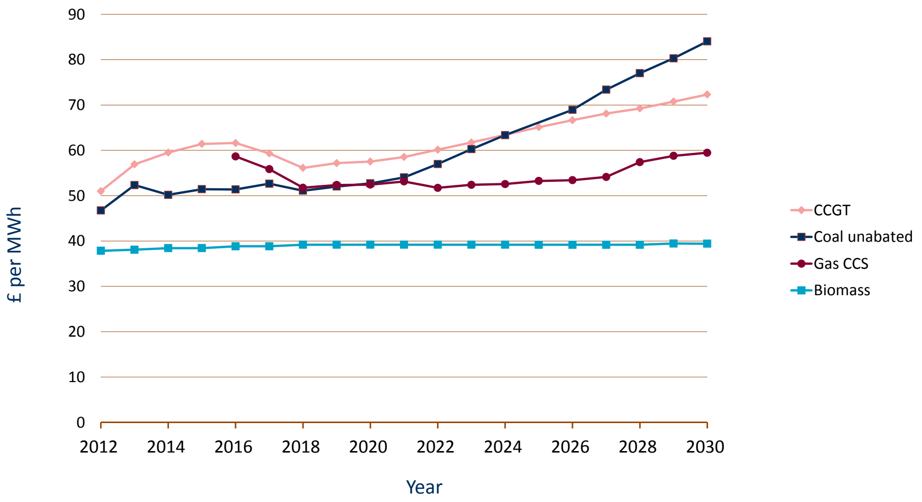
The relative immaturity of the technology and scale of operation, particularly for CCS plant therefore limits the likelihood of market distortion.

15.2. Position of CfD in the merit order

The position of plant in the merit order is determined by the short-run marginal costs (predominantly fuel and carbon costs) and any additional policy effects. Figure 15.1 below shows the short-run marginal costs before any allowance for CfD revenues for conventional thermal plant alongside gas CCS and biomass. The figure illustrates the following:

- Gas CCS has a lower short-run marginal cost than conventional CCGTs. This is due to the reduction in carbon costs for the CCS plant being greater than the increased fuel cost per MWh. Given projected carbon prices it is likely that CCS technologies will have lower short-run marginal costs than their unabated equivalents.
- Biomass has the lowest short-run marginal cost under the central fuel price assumptions.

Figure 15.1: Short-run marginal costs (without CfD effects), 2012 to 2030



Source: LCP

The effect of the CfDs will be to reduce the short-run marginal cost by strike price less the reference price. In order to incentivise new build it is anticipated that the strike price will be higher than the reference price and therefore CfD contracted plant are likely to have lower short-run marginal costs and therefore be lower in the merit order.

However, as can be seen above, gas CCS and biomass sits below conventional CCGT and coal plant in the merit order. This means that the effect of the CfD distortion is not causing any significant change in merit order, although the actual price at which the CfD plant sell power may change.

15.3. Strike and reference price differential

The size of the difference between the strike price and reference price will influence the likely market distortion. The larger the differential the more likely CfD plant will change its position in the merit curve.

16. Baseload CfDs interaction with other renewable policies

As indicated in section 8, the CfD regime will operate alongside the RO.

Under the ROC scheme a dedicated biomass generator is issued 1.5 ROCs per MWh of electricity generated that they could sell into the market for ROCs, as well as selling power.

In terms of ROCs issued, there were 2.0 million (representing 7.9 per cent of the total) issued to dedicated biomass generators in 2010-11.

All biomass plant coming online before 2014 will be under the RO. However, between 2014 and 2017, all plant coming online will have the choice of becoming either a ROC or a CfD plant.

Currently, biomass generating plant sit firmly between the inflexible plant (i.e. wind and nuclear) and the flexible plant (i.e. conventional thermal plant with higher short-run marginal costs).

In theory, there would appear to be the potential for ROC and CfD plant to be competing to generate although this would require a large per MWh subsidy payment which alters their position in the merit order.

If wind was paid on availability, there could be a scenario where negative prices mean that wind stops generating and biomass, under the large per MWh payment, is running. This would seem to be a perverse outcome and likely to be inefficient.

17. Baseload CfD scenarios

Under the base case assumptions (i.e. DECC's central assumptions), the modelling found the distortions caused by baseload CfDs to be negligible. This is because:

- There are low levels of mid-merit CfD deployment
- Biomass and gas CCS generating plant sit firmly between the inflexible plant (i.e. wind and nuclear) and the flexible plant (i.e. conventional thermal plant with higher short-run marginal costs). It would therefore require a large per MWh payment from the CfD to change their position in the merit order.

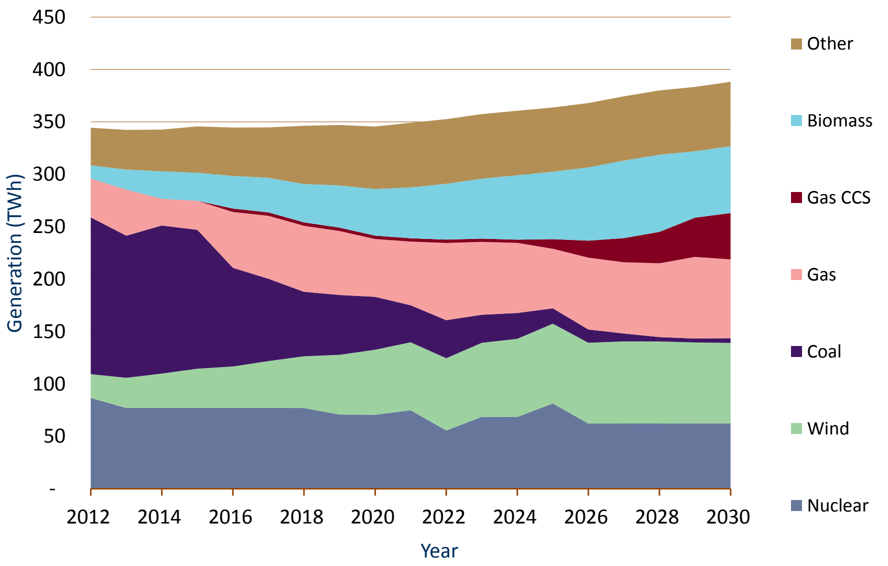
- Projected wholesale power prices are not significantly lower than the strike price.

Instead of analysing the base case in detail, the possible dispatch distortion in a scenario where it becomes more likely with a higher deployment of installed biomass and gas CCS capacity was investigated.

17.1. Higher mid-merit scenario

Figure 17.1 illustrates the generation mix under the higher biomass and gas CCS deployment scenario.

Figure 17.1: Higher mid-merit – Projected generation mix, 2012 to 2030



Source: LCP

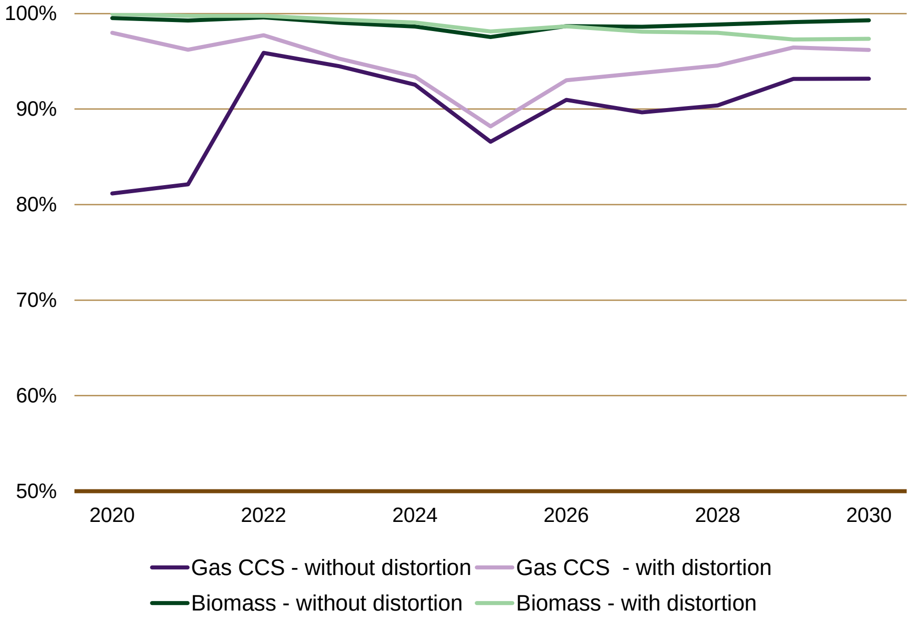
Under this scenario, a total of 13.1GW of mid-merit plant (7.6GW of biomass and 5.5GW of gas CCS) is deployed by 2030. This compares to a total of 4.0GW (1.1GW of biomass and 2.9GW of gas CCS) under the base scenario. As a result of higher level of installed capacity, biomass generates 17 per cent of 2030's projected output (compared to 4 per cent under the base case) and gas CCS 11 per cent (compared to 6 per cent under the base case).

17.2. Higher mid-merit: Results

17.2.1. Load factors under firm volume and metered output

Figure 17.2 illustrates the impact on biomass and gas CCS load factors under metered output ("with distortion") and firm volume ("without distortion) over the period 2020 to 2030

Figure 17.2: Higher mid-merit – Projected load factor distortions under metered output ("with distortion") and firm volume ("without distortion")



Source: LCP

The modelling indicates baseload CfDs under the metered output approach is unlikely to introduce significant distortions with both biomass and gas CCS dispatched ahead of other mid-merit plant.

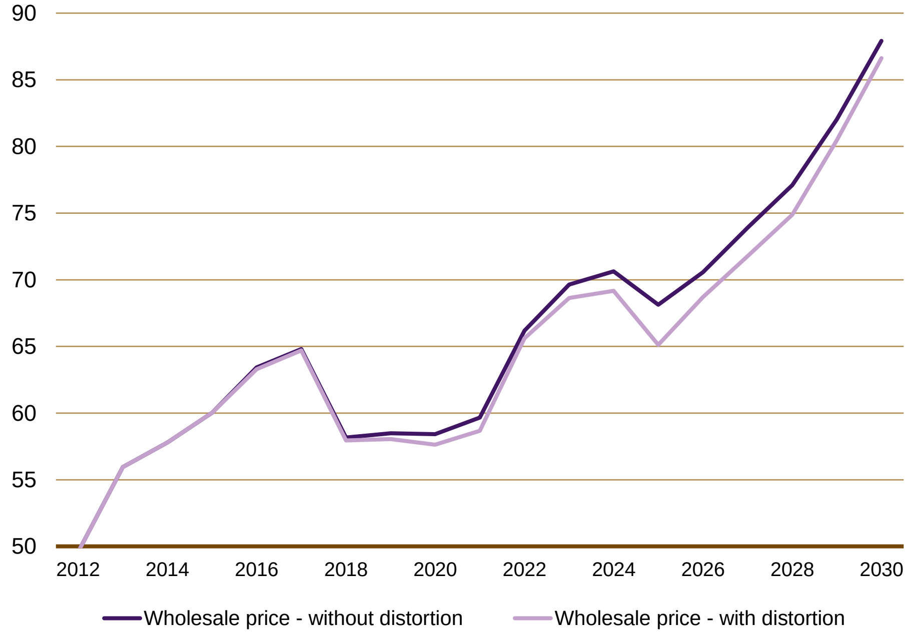
For gas CCS, increasing carbon prices mean that gas CCS plant are pushed sufficiently down the merit curve ahead of other mid-merit plant which results in higher load factors over the whole period.

For the period 2026 onwards, when biomass with and without distortion switches round and gas CCS with distortion starts to diverge again from gas CCS without distortion, this is a result of the strike price being higher for gas CCS which means they receive a higher top-up when compared to biomass, which causes gas CCS to move below biomass in the merit order. Further explanation of the possible inter-technology distortions is set out in section 17.

17.2.2. Impact on wholesale power prices

Figure 16.3 illustrates the projected impact on wholesale power prices under metered output ("with distortion") and firm volume ("without distortion) over the period 2020 to 2030.

Figure 17.3: Higher mid-merit – Projected wholesale power price distortions under metered output ("with distortion") and firm volume ("without distortion")



Source: LCP

Over the whole period, the impact on wholesale power prices for baseload CfDs under metered output is likely to be minimal.

18. Possibility of more extreme distortions under baseload CfDs?

Although the modelling indicates a minimal effect over the period to 2030, there is potential for more significant effects in the longer term. Two types of distortion could be caused by CfDs and result in an increase in total generation costs:

- Inter-technology distortions; and
- Intra-technology distortions.

The following two sections look at each of these distortions in turn.

18.1. Inter-technology distortions

Inter-technology distortion occurs when the technology mix changes due to policy effects.

This issue could be significant if the strike prices or running costs of biomass and gas CCS diverge significantly. Within the modelling that was undertaken, it was assumed that the strike prices are broadly consistent across different technologies.

Another example where this could occur would be if gas price fell significantly relative to biomass and coal costs. In this situation the short-run marginal cost of conventional CCGT may be lower although the effect of the CfD could shift biomass and coal CCS lower in the merit order.

However, in this example the distortion will result in lower carbon emissions and could potentially reduce the need for additional low-carbon investment required to meet emissions targets.

18.2. Intra-technology distortions

Intra–technology distortion occurs when plants of the same technology do not dispatch in-line with their running cost due to policy effects.

This could potentially be significant over the longer term. For example, for CCS technologies it is expected that the efficiency of new build plant will increase over time. However, because of this and the higher uncertainty it is likely that the strike prices for plant commissioned earlier will be significantly higher.

This will potentially give older less efficient CCS plant the ability to reduce the price at which they sell their power to below that of the new more efficient plant.

This could be significant if a period is reached where CCS and biomass plant are able to provide flexible generation to accompany high wind deployment.

19. Possibility of negative pricing under baseload CfDs?

Although the modelling indicates that negative prices are unlikely there are more extreme scenarios where this could occur. Negative prices are possible if for any plant covered by the CfD:

- Strike price minus year-ahead baseload price is greater than running costs

This could happen if:

- High strike prices were needed to incentivise low-carbon generation. This would mean that the additional revenue received per MWh for the mid-merit plant would rise.
- Year-ahead prices fell significantly resulting in larger payment to the generator under the CfD.
- Running costs fell significantly.

A possible situation where this could occur would be if there was a significant fall in gas prices. This would result in both a drop in the year-ahead price and a reduction in the running costs for gas CCS plant.

20. Conclusions

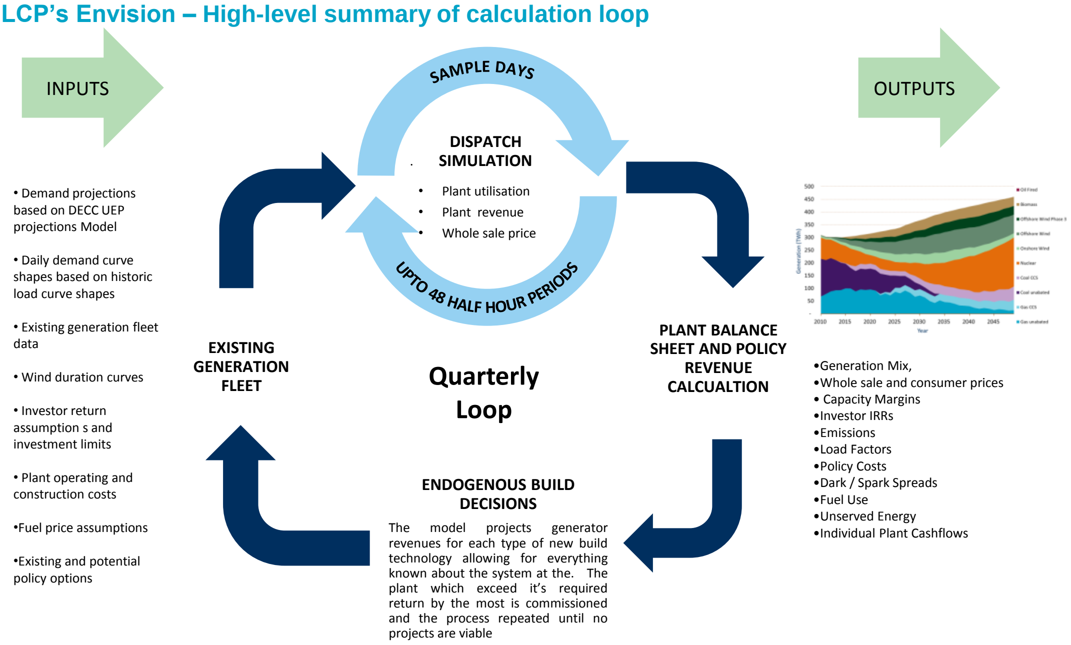
Overall, for baseload CfDs the modelling and analysis did not find any significant distortions due low levels of mid-merit CfD deployment; mid-merit plant sit firmly between the inflexible and flexible plant; and projected wholesale power prices not being significantly lower than the strike price.

Appendix A: LCP's EnVision model

LCP EnVision is designed to analyse the effect of different policy options on the GB electricity market in the long term. It models the life-time of each existing power station through construction, operation and decommissioning. The model also simulates investment decisions in new plant by projecting anticipated revenue streams and comparing that to investment return requirements.

The diagram below shows a high-level summary of the calculation loop.

LCP's Envision – High-level summary of calculation loop



Source: LCP

Appendix B: Data and assumptions

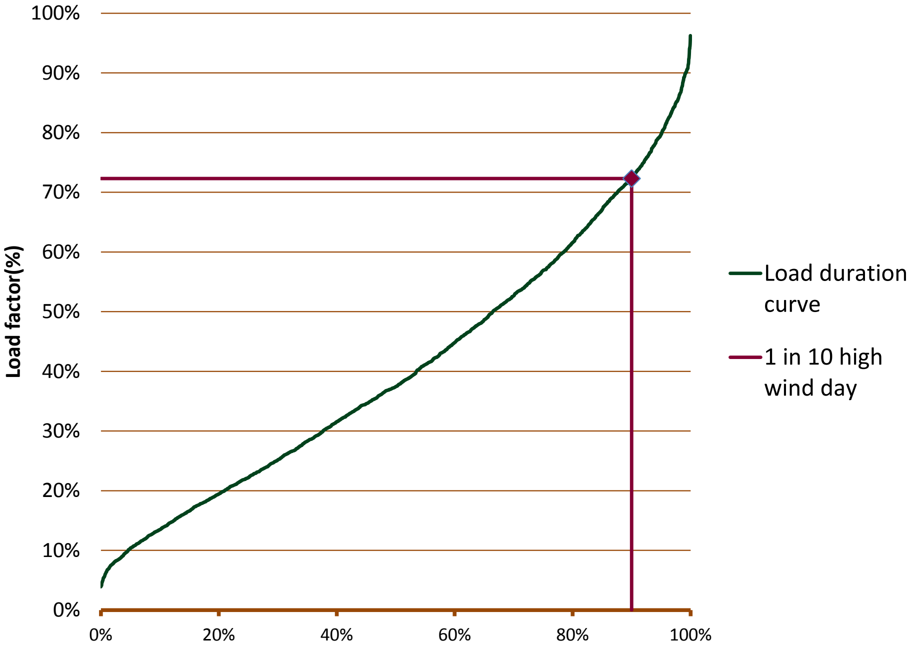
Unless stated otherwise all data and assumptions are in-line with DECC's central assumptions. In addition, the following assumptions were made for the purpose of this analysis.

- All generating plant are assumed to be trading power and reacting to prices so will not generate if it is not economically beneficial to do so.
- Generators sell all of their expected generation in the day-ahead market.
- Day-ahead markets are arbitrage free.
- All market participants have perfect knowledge of the capacity, costs and incentives of other plant on the system.
- Nuclear plant is unable to cease generating when prices become negative. All other technologies are able to respond. In reality some thermal plant may not be able to respond to negative price periods due to operational characteristics such as min on/off times.
- Autogeneration and pumped storage continue to generate at normal levels when prices become negative.
- In periods of negative prices interconnectors do not flow. It is likely that interconnectors would export during these periods but it is possible that a lack of flexibility in the foreign market would lead to imports continuing.
- There is no demand side response to negative prices
- The day-ahead market is priced based on the expected marginal plant in any given half-hour period.
- There is no intra-day variability of wind output.

Appendix C: Wind duration curves

One of the most important assumptions in the analysis of negative prices with intermittent CfDs is the distribution of wind output. The chart below shows the system wide daily wind load duration curve used in the modelling. This curve below is for 2030 and varies depending on the proportion of offshore versus onshore wind.

Wind duration curve for 2030



Source: Provided by DECC

The red line shows the load factor for a 1 in 10 (90th percentile) high wind day which has an average load factor of around 72 per cent.

The average wind load factors used are 30 per cent for onshore wind and 40 per cent for offshore wind. Separate curves have also been used for each season.

Appendix D: Daily load curves

The demand curves that have been modelled for the analysis are based on historic National Grid demand shapes uplifted in-line with DECC's long-term demand projections. No allowance has been made for changes in the demand curve shape due to new developments such as electrification of heat and transport or development in the demand side response technologies.

The daily load curves are chosen to look in detail at low demand periods. They are based on the actual demand curve shapes at the lowest demand periods based on data from 2000 to 2011.

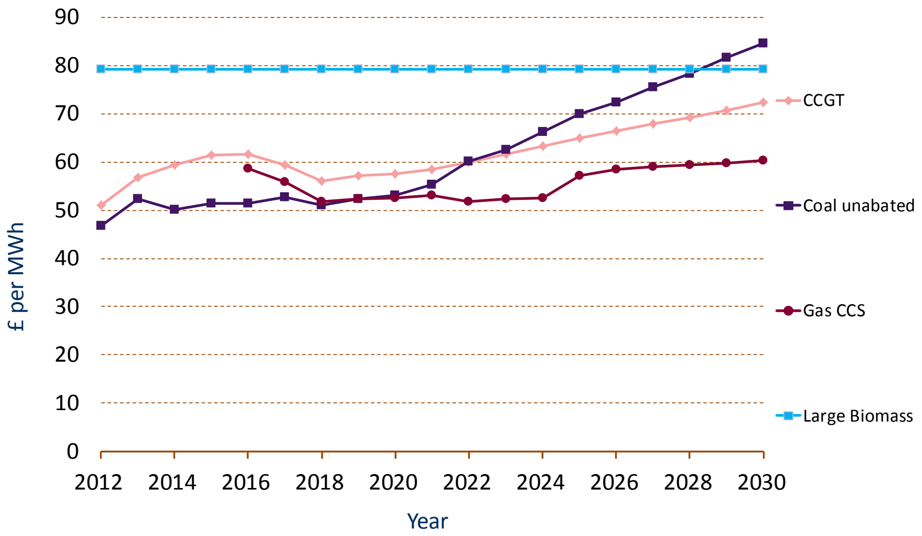
For each season the load curves were ordered by the lowest level of demand in each day. From these days a representative sample was chosen with high granularity around low demand periods.

Appendix E: Addendum – Effect of DECC's revised biomass projections

Within the main CfD report that LCP has prepared for the DECC the effect of dispatch distortions for plant under a baseload CfD was analysed. The analysis compares dispatch of metered output versus firm volume baseload CfDs. The fuel price assumptions made are based on DECC's current projections and imply that biomass plant would run as baseload. The conclusions of the main CfD report are based on this assumption. However, the results are very sensitive to this assumption.

Since the modelling and analysis was undertaken by LCP, DECC has updated its biomass price projections. We have undertaken some analysis of the sensitivity of the results to these new projections; however this analysis was completed late in the study and is indicative only. We have not included interactions with other policies such as the Capacity Mechanism and further work is needed to fully understand the implications of the new price projections.

The new biomass price projections are significantly higher than those used in the analysis in the main report meaning that biomass plant is no longer acting as baseload generation. The chart below illustrates the short-run marginal cost ("SRMC") of large biomass plant relative to other technologies under DECC's revised biomass price assumptions.



With this updated SRMC and ignoring potential effects of other policies, biomass generation receiving a CfD would act as high-mid merit or even peaking plant, rather than as baseload which is the assumed merit position in the main body of the report. Load factors would be less predictable and these plants may seek to agree higher strike prices to off-set this risk.

It is worth noting that the current ROC regime provides sufficient support at the current level of biomass prices to ensure that these plant act as baseload generation, at approximately £60 per MWh (assuming 1.5 ROC per MWh and a buyout price of approximately £40). With the revised biomass price projections this still appears sufficient to ensure that these plant run as baseload.

LCP is a firm of financial, actuarial and business consultants, specialising in the areas of pensions, investment, insurance and business analytics.

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