Analysis of Contract for Difference Supplier Obligation funding options

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Supplier Obligation background

The proposed Electricity Market Reform (EMR) will introduce contracts for differences (CfDs) as the principal mechanism for providing financial support to low carbon generation from 2014. The costs of CfDs will be recovered from electricity suppliers via the Supplier Obligation (SO) Levy, settled on a daily basis. In turn, suppliers are expected to price the cost of the SO into their retail tariffs and supply contracts.

Given variability in output from low carbon generation, and market price variability, the SO Levy has the potential to be highly volatile. In October 2013[1] DECC consulted on the details of a Unit Cost Fixed SO levy, whereby the CfD Counterparty would forecast the expected Market Reference Price, volume of CfD generation, and electricity supply for the period, and set a £/MWh interim rate which suppliers are required to pay in proportion to their supply volume. There would be a reconciliation process at the end of each period to true up the underlying levy by calculating how much each supplier had paid in the preceding period compared with their actual share of CfD payments.

Under the Unit Cost Fixed levy, differences between payments to generators and levy payments received from suppliers would require the CfD Counterparty to hold a reserve fund (RF) to manage forecast uncertainty and cash flow volatility. The reserve fund would be collected from suppliers in advance. It is anticipated that the reserve fund would be sized to enable the CfD Counterparty to have sufficient funds to pay CfD generators up to a specified confidence level[2].

Objectives of the study and approach

Redpoint Energy (a business of Baringa Partners LLP) was commissioned by the Department of Energy and Climate Change (DECC) to provide analysis of payment volatility under CfDs and to assess the size of the reserve fund needed by the CfD Counterparty to manage differences between payments to generators and receipts from suppliers under the Unit Cost Fixed option in two fiscal years, 2017/18 and 2020/21. These two years were chosen to illustrate the growth in payment volatility and reserve fund requirements across the first EMR Delivery Plan. We assessed the impact of the options on the variability of supplier payments and the cash requirements of the CfD Counterparty.

In the October 2013 consultation it was proposed that the reserve fund requirement would be collected from suppliers as a lump sum at the start of each year. The interim rate would be set at the start of the year for the full year, and reconciliation of each supplier's payments against the actual payments required would be performed at the end of the year[3]. Since then DECC has explored options to stage the payments thus reducing the reserve fund requirement. Hence for this study, we analysed the size of reserve fund required under a Unit Cost Fixed levy design for three different funding methods:

- **Annual**: under this option, suppliers would pay the totality of the reserve fund in one lump sum at the beginning of the fiscal year.

[1] It can be found at this address: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255254/emr_consultation_implementation_proposals.pdf

[2] The Reserve Fund size depends on the amount of variability it is set up to cover. For example, if the Reserve Fund is set to cover 95% of all cases, it will be large enough to ensure CfD payments are met every day in 95% of years.

[3] At the end of the fiscal year the CfD Counterparty would true up the payments by calculating how much each supplier paid in the preceding period compared with their actual share of CfD payments (i.e. returning the unspent RF), adjusting for outturn market share. At the same time, a new reserve fund for the following period will be set. Suppliers will pay or receive the difference between these two payments.

- **Staged Quarterly**: under this option, the total amount of the reserve fund is determined at the start of the year but suppliers are only required to pay at the start of each quarter the amount that is estimated (at the start of the year) to be required in that quarter. This way, suppliers will be invoiced for the same total amount of money over the year as under the Annual option, but the staging of payments will reduce financing costs associated with providing the funds.
- **Quarterly Fixed**: under this option, the CfD Counterparty makes a new estimate for the size of the reserve fund each quarter three months in advance, taking into account the additional information available and CfD Counterparty's cash position at the point it sets the RF. This reduces the expected size of the additional payments to the RF, since it is unlikely that the full amount of the reserve fund will have been used in each quarter. Full reconciliation occurs only at year end, as for the Annual and Staged Quarterly options.

It should be noted that the current policy proposal for the Unit Cost Fixed option is to reset the interim rate quarterly with three months' notice, and to perform quarterly reconciliation of the amount paid by each supplier compared to the actual amount required over the quarter. The reconciliation amounts will be netted off the reserve fund payments due from each supplier for the next quarter. The modelling in this study is based on the previous proposal of an annual reset of the interim rate (and annual reconciliation). In general, the updated policy proposal will reduce the reserve fund requirement as there is less opportunity for prices to deviate from the forecast made at the time of interim rate setting.

Our SO policy analysis is underpinned by simulations of market conditions based on DECC assumptions and calibrated on historical data, run through a dispatch model to simulate power prices and CfD generation[4]. These outputs, coupled with simulated electricity demand and specific assumptions on SO policy (e.g. strike prices, allocation of Market Reference Prices to CfD supported technologies, etc.) are then used in a cash flow model in order to calculate CfD and supplier payments, as well as reserve fund size under the funding mechanisms considered here. The SO Levy will likely impact the cash requirements and pricing and hedging strategies of suppliers but this was not modelled explicitly.

Variability of supplier payments

In the modelling, the annual payments to CfD generators average £684m in 2017/18 and £2.7bn in 2020/21[5], with a standard deviation[6] in annual payments between simulations in percentage terms of 23% in 2017/18 and 19% in 2020/21.

Under a **Fully Variable** SO levy, where suppliers are exposed to the full variability of Market Reference Prices and CfD generation, the volatility[7] of SO Levy payments settled on a daily basis, as measured by the standard deviation, is approximately 41-44% of the average. If settlement took place on a weekly or monthly basis the volatility would reduce to approximately 29-32% and 23-27% respectively, since it is statistically unlikely that extreme market conditions would persist for long periods of time.

Under a **Unit Cost Fixed** levy, the volatility of daily interim rate payments is approximately 13%, much lower than in the Fully Variable option because in the Unit Cost Fixed option, suppliers are only exposed to electricity demand variability, which is small relative to the variability in CfD payments. Note that this

[4] Appendix A describes in detail functioning of the dispatch model as well as its inputs and their calibration to historical data.

[5] Modelled CfD payments are based on Final Delivery Plan 2013 modelling, and include implicit assumptions on both future capacity mix, and the relative levels of deployment under each LCF support scheme. As these are modelled assumptions, they may be subject to changes in the future and should not be interpreted as the CfD budgets. The CfD budgets will be set by DECC in July 2014.

[6] Approximately 68% of outcomes lie within one standard deviation of the mean.

[7] We use the volatility of SO payments as a measure of the risk carried by suppliers. The volatility is calculated as the ratio of the standard deviation to the average value.

does not take into account the variability of reconciliation or reserve fund payments on a quarterly or annual basis.

Unit Cost Fixed rates and reserve fund requirements

Under the modelled Unit Cost Fixed levy, the interim rate is fixed annually based on the expected level of CfD payments and electricity supply, which is proxied using the average outcomes across all simulations. In the modelling the interim rate rises from £2.1/MWh[8] in 2017/18 to £8.3/MWh in 2020/21, as CfD-supported generation increases.

The annual size of the reserve fund required by the CfD Counterparty would be £275m in 2017/18 and £821m in 2020/21 in a p-95[9] case. Relaxing this to p-90 would reduce the reserve fund requirement by approximately £52m in 2017/18 and by £71m in 2020/21. Tightening this requirement to p-99 would increase the reserve fund size by £55m in 2017/18 and by £108m in 2020/21. Under a Quarterly Fixed funding mechanism, the estimated average annual reserve fund requirement would decrease to represent £197m in 2017/18 and £577m in 2020/21. The costs of financing[10] the cash reserve fund would range from £19m in the Annual option, to £8m in the Staged Quarterly option and £6m under the Quarterly Fixed option in 2017/18. For 2020/21, these costs are £55m for the Annual option, £27m for the Staged Quarterly option and £7m for the Quarterly Fixed option.

Under a Fully Variable design the SO Levy reflects the underlying variation in payments to generators and there is no requirement for a central RF. Instead suppliers will need to make their own provisions for managing payment volatility. The extent to which this results in additional funding costs to suppliers would depend on how their wider hedging and pricing strategies adapted to a Fully Variable SO Levy. This wider consideration of the impact of the different SO Levy options on supplier hedging and pricing strategies was not within the scope of this study.

Conclusions

The analysis demonstrates the range of variation in CfD payments to generators that might be expected on an annual and daily basis, considering the impact of variability in gas prices, wind generation and demand. Our modelling of a Fully Variable and Unit Cost Fixed SO Levy demonstrates the differences in the timing and volatility of payments to the CfD Counterparty.

A Fully Variable levy puts the onus on suppliers to manage the variability associated with day-to-day CfD payments. Under a Unit Cost Fixed levy, the variability is largely managed centrally, but suppliers must pay into a reserve fund to act as a buffer. Under both options the risk of CfD payments in outturn being higher or lower than expected over the course of the year remains with suppliers. While CfD variability risk is explicitly transferred to suppliers in a Fully Variable levy (and they would be expected to make internal funding provisions to cover any variability in CfD payments), under a Unit Cost Fixed levy suppliers are exposed to reconciliation payments at the end of the Levy period to account for differences between expected and actual CfD payments, as well as any adjustment to the size of the reserve fund for the next period to cover increases in the expected CfD payments (e.g. if new CfD generators are expected to be commissioned).

[8] All the results are expressed in real 2012 GBP.

[9] We use p-statistics in this study (e.g. p-95) to represent a level of risk: e.g. a p-95 case represents a 95% confidence that the Reserve Fund will be sufficient. The Reserve Fund requirement in a p-90 case will then be less than the Reserve Fund requirement in a p-99 case.

[10] Cost of capital is assumed to be 6.744%, as per the SO Impact Assessment document.

1. BACKGROUND AND RATIONALE

1.1. Introduction

This section sets out the background to the study, introduces the main features of the CfD Supplier Obligation and finally lays out the scope and content of the analysis.

The proposed Electricity Market Reform (EMR) will introduce contracts for differences (CfDs) as the principal mechanism for providing financial support to low carbon generation. CfDs will be introduced in 2014 and replace the existing Renewables Obligation (RO) for new low carbon generators completely by 2017. Unlike the RO where suppliers are individually responsible for procuring certificates to meet their obligations, CfDs will be administered centrally via a new central body, the CfD Counterparty. The CfD Counterparty will pay generators based on their output and the difference between each generator's strike price and the Market Reference Price specified in their CfD. Assuming that the generator receives the Market Reference Price for selling the electricity generation on the market, the CfD effectively provides a fixed price for the generator's output.

Equation 1 sets out how CfD payments to low carbon generators are calculated.

Equation 1 CfD payments calculation method[11]

$$CfD\ payments = CfD\ generation * (Strike\ price - Market\ Reference\ Price)$$

The Market Reference Price is either the Intermittent Market Reference Price (for intermittent generation) which is based on a day-ahead index, or the Baseload Market Reference Price (for dispatchable generation) which will be based initially on a season-ahead index (see Section 2.3.2).

The strike price is defined for each generator when it is allocated a CfD. Each generator will receive a single strike price for the duration of the CfD, subject to indexation (e.g. for inflation and certain other costs) or other agreed adjustments (e.g. for compensation payments).

1.2. Supplier Obligation policy overview

The costs of supporting low carbon generation through CfDs will be passed on to suppliers via the Supplier Obligation (SO) Levy. In turn, it is anticipated that suppliers will price the cost of the SO into their retail tariffs and supply contracts.

In November 2012 DECC issued a call for evidence on the proposed design of the Supplier Obligation[12]. Based on feedback from this call for evidence DECC undertook further analysis and consultation with industry. In August 2013 it published a Policy Update and Response to the Call for Evidence[13], in which DECC laid out four policy options to recover SO costs from suppliers:

- **Fully Variable**: suppliers are invoiced for outturn CfD costs shortly after they are incurred (and thus exposed to the full volatility).

[11] Terms such as indexation have been ignored in this simplified calculation

[12] Annex A of the Electricity Market Reform policy overview: https://www.gov.uk/government/publications/electricity-market-reform-policy-overview--2

[13] The document can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226897/CfD_Supplier_Obligation_-_policy_update_and_response_to_the_call_for_evidence__-_7_August_2013__-_FINAL.pdf

- **Generation Fixed**: the CfD Counterparty forecasts expected CfD generation volume, invoicing suppliers based on the actual strike prices and Market Reference Prices but the forecast, rather than outturn, generation volume.
- **Unit Cost Fixed**: the CfD Counterparty forecasts the expected Market Reference Price, volume of CfD generation and electricity supply for the period, setting a £/MWh rate (called the **interim rate**) which suppliers are invoiced in proportion to their supply volume.
- **Fully Fixed**: the CfD Counterparty forecasts the Market Reference Price and CfD generation, then sets a fixed cost for each supplier throughout the period.

In the response to the Call for Evidence, DECC indicated a preferred policy position of the Unit Cost Fixed rate approach and consulted on details of this approach in October 2013[14], including the process for setting the interim rate and requirement for a reserve fund (RF).

Since the interim rate would be based on a forecast at the start of each year, there would be a reconciliation process of the interim rate payments after the end of the year to adjust how much each supplier had paid in the preceding year so it matched their actual share of CfD payments. Since the October 2013 consultation the preferred policy position has evolved to a quarterly reset for the interim rate with three months' notice. The analysis in this report pre-dated the change in policy position, and hence is based on an annual reset of the interim rate.

The differences between payments to generators and supplier payments would require the CfD Counterparty to hold a reserve fund to manage cash flow volatility. The reserve fund would be collected from suppliers in advance. It is anticipated that the reserve fund would be sized to enable the CfD Counterparty to have sufficient funds to pay CfD generators up to a specified confidence level[15].

In the October 2013 consultation it was proposed that the reserve fund requirement would be collected from suppliers as a lump sum at the start of each year. The interim rate would set at the start of the year for the full year, and reconciliation of each supplier's payments against the actual payments required would be performed at the end of the year[16]. Since then DECC has explored options to stage the payments thus reducing the reserve fund requirement. Hence for this study, we analysed the size of reserve fund required under a Unit Cost Fixed levy design for three different funding methods:

- **Annual**: under this option, suppliers would pay the totality of the reserve fund in one lump sum at the beginning of the fiscal year.
- **Staged Quarterly**: under this option, the total amount of the reserve fund is determined at the start of the year but suppliers are only required to pay at the start of each quarter the amount that is estimated (at the start of the year) to be required in that quarter. This way, suppliers will be invoiced for the same total amount of money over the year as under the Annual option, but the staging of payments will reduce financing costs associated with providing the funds.
- **Quarterly Fixed**: under this option, the CfD Counterparty makes a new estimate for the size of the reserve fund each quarter three months in advance, taking into account the additional information available and CfD Counterparty's cash position at the point it sets the RF. This reduces the expected size of the additional payments to the RF, since it is unlikely that the full amount of the reserve fund

[14] It can be found at this address:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255254/emr_consultation_implementation_proposals.pdf

[15] The Reserve Fund size depends on the amount of variability it is set up to cover. For example, if the reserve fund is set to cover 95% of all cases, it will be large enough to ensure CfD payments are met every day in 95% of years.

[16] At the end of the fiscal year the CfD Counterparty would true up the payments by calculating how much each supplier paid in the preceding period compared with their actual share of CfD payments, adjusting for outturn market share (i.e. returning the unspent RF). At the same time, a new reserve fund for the following period will be set. Suppliers will pay or receive the difference between these two payments.

will have been used in each quarter. Full reconciliation occurs only at year end, as for Annual and Staged Quarterly.

It should be noted that the current policy proposal for the Unit Cost Fixed option is to reset the interim rate quarterly with three months' notice, and to perform quarterly reconciliation of the amount paid by each supplier compared to the actual amount required over the quarter. The reconciliation amounts will be netted off the reserve fund payments due from each supplier for the next quarter. The modelling in this study is based on the previous proposal of an annual reset of the interim rate (and annual reconciliation). In general, the updated policy proposal will reduce the reserve fund requirement as there is less opportunity for prices to deviate from the forecast made at the time of interim rate setting.

Table 1 Funding methods

Funding method	Interim rate setting	Reserve fund setting	Reconciliation
Annual	Annual	Annual	Annual
Staged Quarterly	Annual	Annual	Annual
Quarterly Fixed	Annual	Quarterly	Annual
Latest DECC policy position	*Quarterly*	*Quarterly*	*Quarterly*

1.3. Context and scope of our analysis for DECC

In response to the October 2013 consultation, DECC commissioned Redpoint Energy (now part of Baringa Partners) to undertake a more detailed, probabilistic assessment of CfD payment volatility, the impact on the CfD Counterparty's cash flows and the size of reserve fund needed, taking into account uncertainty and variability of electricity prices, low carbon output and demand. The analysis built on previous work we had undertaken for DECC in support of its analysis of the Call for Evidence responses in February 2013.

In this report we assess the volatility of CfD payments and the impact of a Fully Variable and Unit Cost Fixed SO Levy on the cash requirements of the CfD Counterparty in two fiscal years, 2017/18 and 2020/21. These two years were chosen to illustrate the growth in payment volatility and reserve fund requirements across the first EMR Delivery Plan. We also evaluate the impact of the funding mechanisms described above on financing costs of the reserve fund for suppliers.

This document is organised as follows:

- Section 2 introduces the modelling framework underpinning the SO analysis;
- Section 3 presents the main results from the market modelling including distributions of electricity prices, CfD generation volumes and CfD payments; and
- Section 4 lays out the results of our analysis of the Fully Variable and Unit Cost Fixed SO policy options including a review of risks associated with each one.

The Appendices present further details of our modelling approach (Appendix A), additional modelling results (Appendix B) as well as a glossary of terms (Appendix C).

2. MODELLING FRAMEWORK

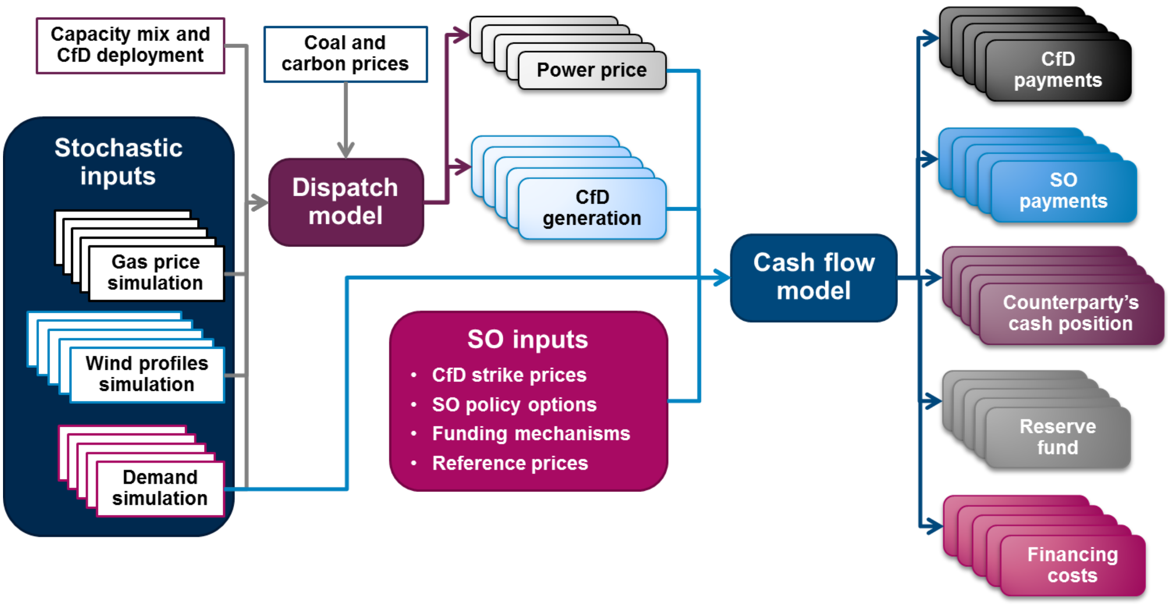
2.1. Overview

The aim of the analysis is to evaluate the variability of CfD payments, and the reserve fund requirements, given uncertainty in future gas prices, demand and wind generation. In this study, we assume that the CfD Counterparty estimates a range of possible outcomes for the next fiscal year in the preceding November, and sets the interim rate and reserve fund (if applicable under the policy option) on this basis. As noted above the analysis pre-dated the change in preferred policy position to a quarterly reset of the interim rate. This section describes the modelling framework employed in this analysis, which combines a dispatch model and a cash flow model:

- The **dispatch model** (PLEXOS) is used to produce outputs for GB wholesale market prices and CfD-supported generation by simulating stochastically the GB electricity system under multiple cases to produce distributions of outcomes (CfD generation, reference prices).
- The **cash flow model** uses outputs from the dispatch model combined with SO policy features to calculate distributions in payments, and estimate the size of reserve fund required under each SO policy.

Figure 1 schematically presents the modelling framework used in this analysis.

Figure 1 Modelling framework overview



2.2. Dispatch model

2.2.1. Overview of dispatch model

The tool used to model electricity system dispatch, PLEXOS, is third party power market modelling software which we have configured for the GB electricity market using DECC's assumptions on capacity mix, fuel and carbon prices[17]. Where applicable, we use DECC assumptions for forward projections, for example future CfD generation capacity and fuel and carbon prices. Variability in low carbon generation,

[17] These assumptions come from the December 2013 Delivery Plan. This document can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

demand and spot gas prices (relative to forward market prices) is captured through sampling of historic data sets[18]. Details of the Great Britain generation system configured in the dispatch model are based on Baringa assumptions sourced from publically available information.

The dispatch model runs for fiscal years 2017/18 and 2020/21 under 100 stochastic (randomly sampled) simulations and outputs a set of hourly power prices and hourly CfD generation for each CfD-supported technology. These outputs are further described in Section 3.

The main inputs to the dispatch model as well as the modelling techniques employed to gather them are discussed in the following sections.

2.2.2. Monte Carlo simulations

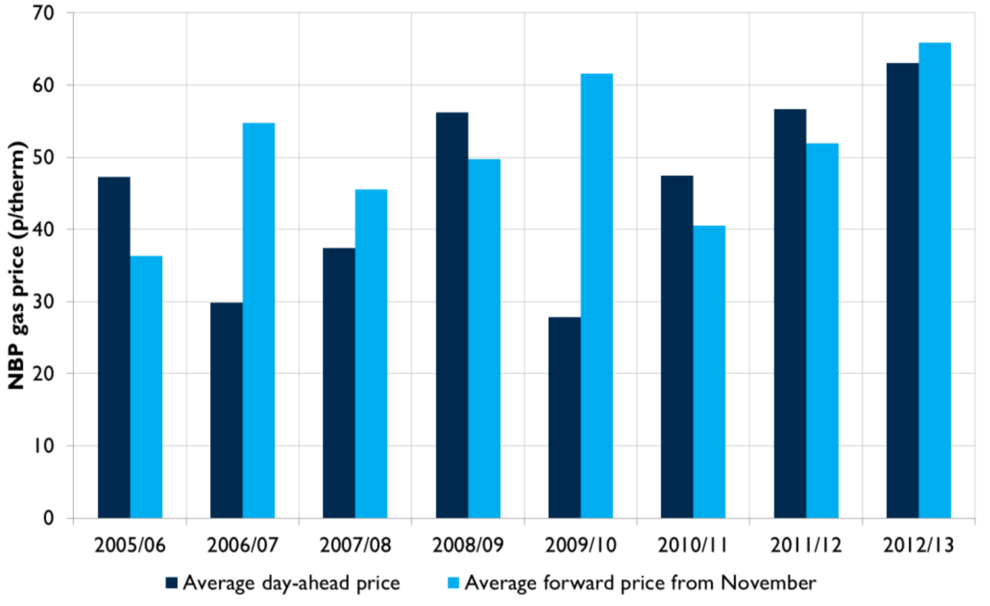
For each fiscal year considered, the model generates 100 sets of inputs for hourly wind generation, daily gas prices, and hourly electricity demand and runs the dispatch model for each set, producing 100 corresponding simulations of GB power prices and CfD generation. This method is called a Monte Carlo simulation. Variable inputs into our power dispatch model include:

- **Gas price**: our model simulates gas prices from the standpoint of the CfD Counterparty estimating possible scenarios for the next fiscal year in the previous November. From a technical perspective, gas prices are simulated using a process combining a Brownian motion and a mean-reverting drift, calibrated to eight years of historical data. This simulated gas price is then scaled to reflect historical forward premiums/discounts observed from November to the next fiscal year (see Figure 2) and secondly such that the average price from all simulations matches DECC's UEP forecasts[19];
- **Wind output**: we use 20 years of wind speed historical data coupled with a typical wind power curve to generate wind output in nine regions across GB; and
- **Electricity demand**: GB electricity demand is modelled as an annual demand (following a normal distribution based on historical year-on-year variation of GB electricity demand over 16 years) coupled with an hourly profile drawn from eight historical profiles.

[18] For simplicity we did not consider variability in coal and carbon prices, since gas prices are the far more significant contributor to power price variability.

[19] This document can be found at this address: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/254831/Annex-f-price-growth-assumptions-2013.xls

Figure 2 **Historic gas forward price premiums/discounts relative to outturn spot prices**



Appendix A details the modelling techniques and assumptions used for the simulation of these three variables. Coal and carbon prices are aligned with DECC's UEP central case[20].

2.2.3. Capacity mix and running profiles

The modelled GB capacity mix is aligned to Scenario 1 of the EMR Final Delivery plan[21] published in December 2013. This scenario achieves 33% of renewable electricity in 2020. We note that payment volatility will be significantly affected by technology mix, assumptions for which are likely to evolve over time relative to the December 2013 assumptions.

At a monthly level, CfD generators' running profiles fall into one of three categories. While biowaste, energy from waste (EfW), hydro, solar PV[22] and tidal technologies are modelled with fixed profiles[23] throughout the year, biomass conversion, gas and coal CCS are dispatched based on market price (subject to availability), and onshore and offshore wind generators load factors are simulated in the model based on wind speed simulated from 20 years of historic data.

Further description of the PLEXOS model and the assumptions used can be found in Appendix A.

[20] This document can be found at this address: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/254831/Annex-f-price-growth-assumptions-2013.xls

[21] Table 4 (p40) presents projected total capacity by technology in 2020. The document can be found at this address: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

[22] The running profile of solar PV varies with the season as well as diurnally.

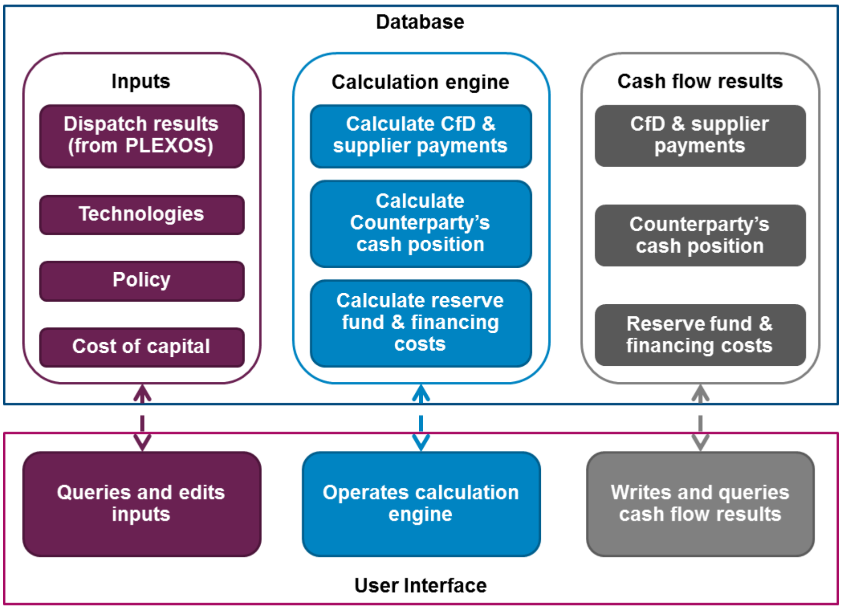
[23] Load factor assumptions are detailed in Appendix A.

2.3. Cash flow model

2.3.1. Overview of cash flow model

The SO cash flow model is used to calculate SO key metrics (CfD and supplier payments, CfD Counterparty cash balance, reserve fund size and financing costs) under different market simulations (simulated in the dispatch model) and the two SO policy options analysed here: Unit Cost Fixed and Fully Variable.

Figure 3 Cash flow model architecture



As represented in Figure 3, the SO cash flow model is composed of two components:

- A database, containing input data, a calculation engine and results from the cash flow modelling; and
- A user interface, which is designed to query and edit policy and market inputs, operate the SO calculation engine, write metrics to the database and review them.

The cash flow model database holds the inputs data and the algorithm required to calculate SO key metrics. Input data are classified in four different categories in Figure 3:

- **Dispatch results**: hourly CfD generation, hourly power prices used as proxy for Market Reference Prices as well as daily electricity demand coming from the dispatch model.
- **Technology data**: CfD strike prices, Market Reference Price type and deployment rates associated with each CfD technology.
- **Policy data**: SO policy options and funding mechanisms described in Section 1, payment periods for CfD generators and suppliers to model the delay between when payments are calculated and when they are due.
- **Cost of capital assumptions**: set to 6.744% according to the SO Impact Assessment document.

The calculation engine uses the inputs above to

- Calculate daily CfD payments to (and from) each technology as set out in Equation 1;

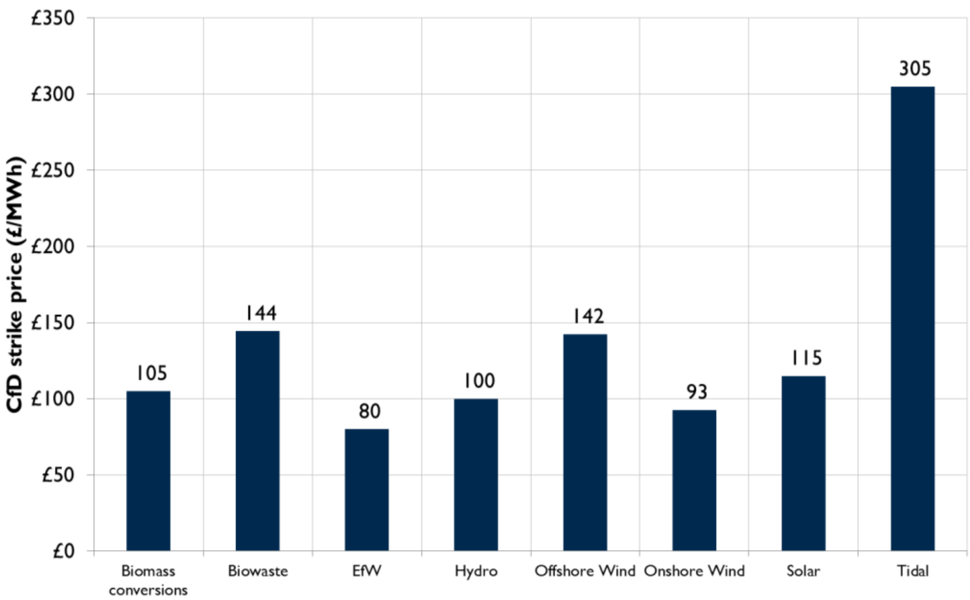
- Calculate daily supplier payments from suppliers in Fully Variable and Unit Cost Fixed policy options using the logic set out in Section 1.2;
- Calculate the CfD Counterparty's cash position by aggregating cash flows from suppliers and to CfD generators at their due dates;
- Calculate the required reserve fund for each simulation as the largest negative cash balance over the Levy period (for Annual and Staged Quarterly funding mechanisms) or by applying the method described in Box 1 for Quarterly Fixed (see Section 4.4.2). These simulations are then ranked by order of increasing reserve fund size[24]; and
- Calculate financing costs for each of the simulated fiscal years.

In the following sections we describe in greater detail the remaining inputs of the cash flow model.

2.3.2. CfD strike and Market Reference prices

Strike prices for 2017/18 were taken from Scenario 1 of the EMR Final Delivery Plan published in December 2013[25]. These are administrative strike prices; outturn strike prices could be lower if set via the competitive allocation process. Strike prices for 2020/2021 reflect DECC internal projections. CfD strike price trajectories tend to decrease reflecting technology development, learning rates and budget constraints as they approach commercial maturity[26]. For each technology, we calculate "vintaged" strike prices as the weighted average of strike prices by capacity deployed in each year. "Vintaged" strike prices for each CfD technology are shown in Figure 4 for 2017/18.

Figure 4 Vintaged CfD strike prices for selected technologies in fiscal year 2017/18



The Market Reference Prices apply to the modelled technologies as follows:

[24] Ranking simulations allows for defining p-statistics where p-1 represents the best and p-100 the worst cases respectively.

[25] Table 3 (p37) in the EMR Delivery Plan details Strike Price evolution out to 2018/19. Other Strike Prices (e.g. CCS) come from DECC modelling. The EMR Delivery Plan is available here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

[26] In our modelling, we lower the short-run marginal cost (SRMC) of generation of dispatchable CfD supported technologies (gas and coal CCS, biomass conversions) so that their bids would take into account the support provided by CfD payments. In practice, this ensures that these generators run to their full availability.

- The Intermittent Market Reference Price applies to offshore wind, onshore wind, Scottish islands onshore wind, solar and tidal; and,
- The Baseload Market Reference Price applies to biomass conversions, biowaste, coal CCS, energy from waste (EfW), gas CCS, and hydro.

The dispatch model produces outturn hourly power prices, which we use to represent the day-ahead Intermittent Market Reference Prices in this analysis. We do not model forward prices, and therefore Baseload Market Reference Prices are approximated by the annual average of the hourly prices.

2.3.3. Payment periods

In the cash flow model, we set payment periods as described in the SO Impact Assessment:

- 28 calendar days for CfD generators[27]; and
- 19 calendar days for suppliers, which is a simplification of the assumption of 13 business days set out in the SO impact assessment[28].

2.4. Modelling limitations

Table 2 below summarises the modelling assumptions and simplifications made for this study and assesses their potential impacts on results, particularly CfD payments and reserve fund size.

Table 2 Modelling limitations impacts on the RF

Cate-gory	Feature	Impact on the reserve fund size	Materiality of impact
Variability of CfD generation	Modelled wind distribution is based on historic data. More extreme wind output could be observed (higher or lower). This would widen the distribution of outcomes.	This would **increase** the reserve fund size.	Low likelihood but high impact given the projected wind capacity online by 2020.
	Variability in load factors for biowaste, EfW, tidal and solar is not captured in modelling.	This could **increase or decrease** the reserve fund size.	Low impact because energy generated by these technologies under CfDs is small compared to wind.
Fuels and carbon prices	The difference between forecast (forward) gas prices and outturn prices could be **greater** than captured in the range of simulations based on historic price patterns.	This would **increase** the reserve fund size.	Low likelihood but high impact because gas price is the main driver of power price.
	Actual gas prices could turn out to be **higher or lower** than simulated ones.	This would **decrease or**	Low likelihood but high impact because gas price is the main driver of power price.

[27] Cf. SO Impact Assessment – October 2013 (p21)

[28] Cf. SO Impact Assessment – October 2013 (p10)

Category	Feature	Impact on the reserve fund size	Materiality of impact
		increase the reserve fund size.	
	The model does not capture within-year variation in coal and carbon prices.	This would **increase** the reserve fund size.	Low impact because a) coal-fired plant do not set power price often and b) carbon price variation is small compared to SRMC of gas-fired plant.
	CPF rises to £32/tonne of CO2 by 2020/21 in our modelling, which was conducted before the Budget 2014 froze CPF prices at £18/tonne from 2016/17.	No impact (see comment)	Electricity prices would be lower than modelled increasing the size and volatility of CfD payments. Note, however, that CPF levels should always be known in advance of setting the interim rate and hence reserve fund does not need to be sized to cover uncertainty in CPF levels.
Power prices	Modelled CfD Baseload Market Reference prices are based on outturn prices when in reality they would be set based on forward prices, which are expected to be less volatile.	This would **decrease** the reserve fund size.	Medium impact in 2017 and low impact in 2020 as more intermittent CfD technologies are deployed.
Demand	Future demand could be more volatile than observed historically.	This would **increase** the reserve fund size.	We would expect this to have a small effect compared to price variability.
Demand	Positive correlation between gas prices and power demand not captured in our model (e.g. in periods of cold weather) would increase interim rate payments from suppliers in Unit Cost Fixed option while CfD payments may go down.	This would **decrease** the reserve fund size.	Low materiality as demand sensitivity to temperature is a lesser driver of reserve fund size than power price.
Capacity	Uncertainty on generation start dates is not captured. If published/contracted commissioning dates are used, significant early commissioning is unlikely. Delays would decrease the reserve fund size.	This would **decrease** the reserve fund size.	Low impact depending on how much technology is delayed and by how long.
Capacity	CfD technologies in early development could have lower availability in their first years of operation.	This would **decrease** the reserve fund size.	Low impact because such technologies generate only a small fraction of CfD-supported generation.

Cate-gory	Feature	Impact on the reserve fund size	Materiality of impact
SO policy	Strike price vintaging used to model actual evolution of strike prices and payment schedule simplification.	N/A	This should have very limited to no impact on the reserve fund size and CfD payments.
	CfD payments and demand are not re-forecast each quarter when the new reserve fund amount is determined (Quarterly Fixed only).	This would **decrease** the reserve fund size (Quarterly Fixed only)	Reforecasting would reduce the range of expected outcomes and therefore reduce the required reserve fund size.
	The interim rate is set on an annual basis, rather than re-set each quarter (Quarterly Fixed only).	This would **decrease** the reserve fund size (Quarterly Fixed only)	In general, the quarterly reset of interim rate should reduce the reserve fund requirement since there is less opportunity for prices to deviate from those forecast at the time of interim rate setting.

3. RESULTS FROM DISPATCH MODEL

3.1. Overview

Variability in payments to CfD generators is the main driver of the required reserve fund and therefore these results are the main inputs to the policy analysis in Section 4. This section presents results from our dispatch model, namely power prices (and wholesale electricity cost to suppliers), electricity generation from CfD-supported technologies, and payments to CfD generators.

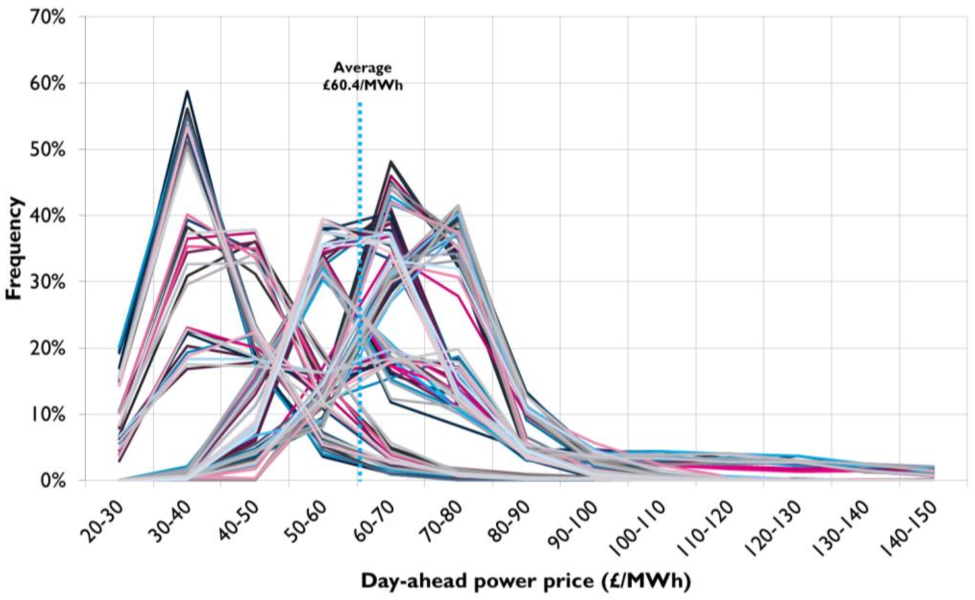
3.2. Power prices

3.2.1. Drivers of power prices

One of the most important drivers of power prices in the GB market is the price of gas, which is a key component of the running cost of a gas-fired power station. We run our dispatch model under 100 different scenarios of gas prices[29] (with parameters based on one of eight historic years). In both years modelled (2017/18 and 2020/2021), we can see clusters of simulations where the model runs with gas prices simulated using parameters from the same historic year. Variations within these clusters can be attributed to gas price variations and the secondary drivers of demand and wind generation.

Figure 5 shows the distribution of hourly power price results for fiscal year 2017/18. Each line represents one year of hourly power prices simulated within our Monte Carlo approach.

Figure 5 Distribution of simulated hourly power prices (fiscal year 2017/18)



Average annual wholesale power prices range from £37/MWh to £75/MWh in fiscal year 2017/18 and from £38/MWh to £83/MWh in fiscal year 2020/21. The average annual power price across the set of 100 simulations rises slightly from £60.4/MWh in 2017/18 to £62.3/MWh in 2020/21, due to increases in assumed commodity prices.

[29] Gas prices are simulated using a mean-reverting model and then scaled to represent the forward premium/discount for the next fiscal year from the previous November. Gas prices are finally scaled such that the average matches DECC UEP forecasts.

Figure 6 shows the distribution of hourly power price results for fiscal year 2020/21. Each line represents one year of hourly power prices simulated within our Monte Carlo approach.

Figure 6 Distribution of simulated hourly power prices (fiscal year 2020/21)

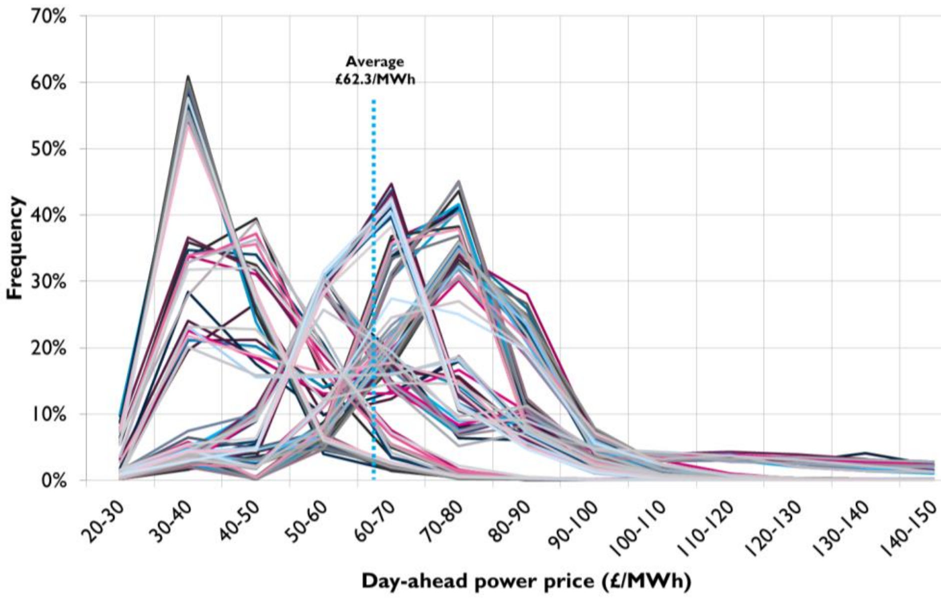
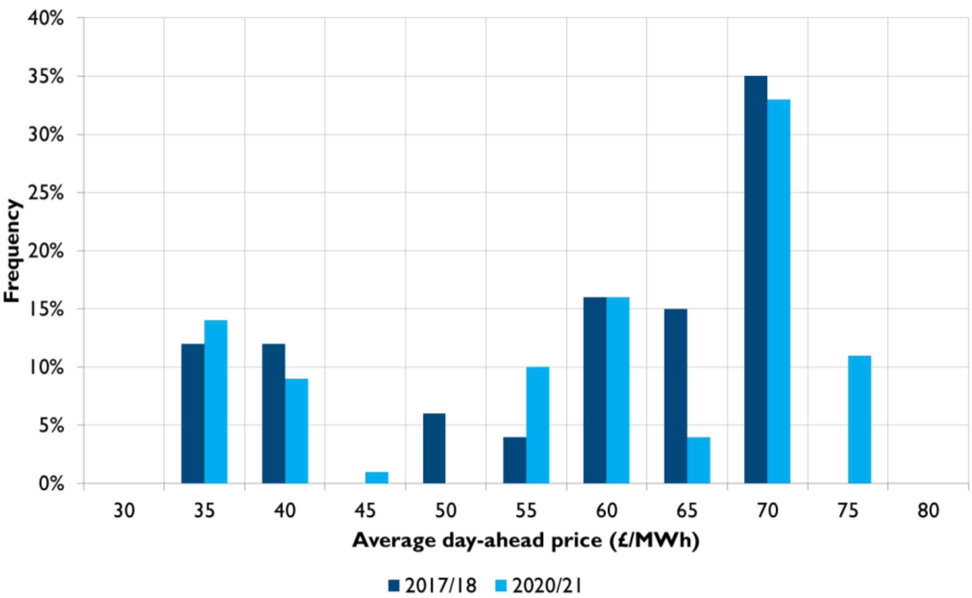


Figure 7 shows the distribution of annual day-ahead power prices, which confirms the picture on an hourly level, as it displays a cluster of simulations (~20 to 25%) in the £35-45/MWh price range while most simulations (50~65%) end up in the £60-75/MWh price range. This is a reflection of the average price of gas over the historical years used to calibrate our model. Furthermore, both fiscal years modelled show similar patterns, with 2020/21 having slightly more extreme values.

Figure 7 Distribution of average day-ahead power prices in fiscal years 2017/18 and 2020/21



3.2.2. Power price profiles

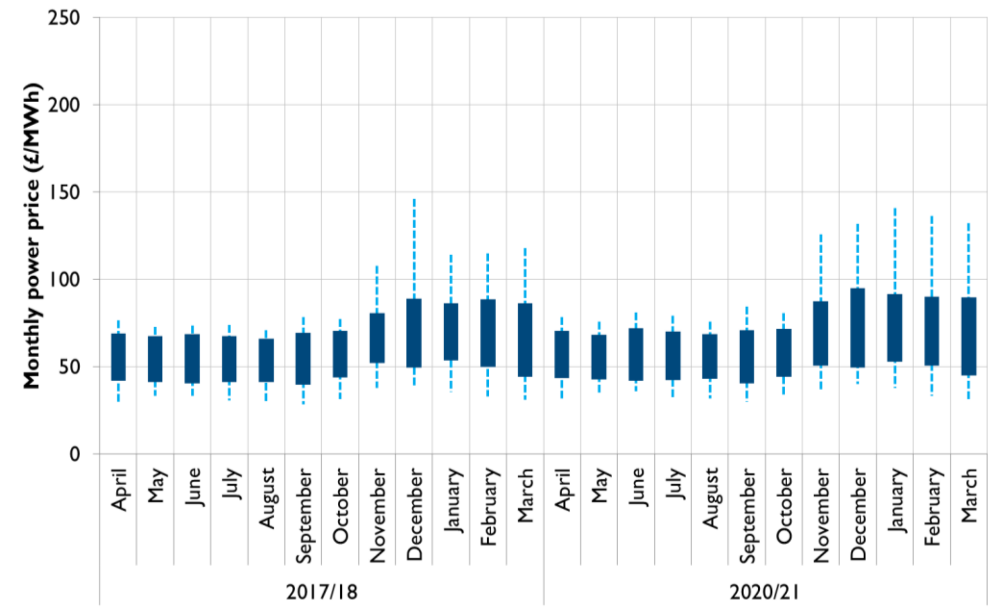
Monthly granularity

Figure 8 shows monthly power price profiles for both fiscal years modelled. The dark blue bar represents prices within one standard deviation of the average monthly price, while the light blue dotted line stretches from minimum to maximum price observed during the month.

In 2017/18, we observe periods of high volatility from December through March with standard deviations of £19/MWh as well as periods of lower volatility from April to November when standard deviations average £14/MWh. In 2020/21, the period of high volatility stretches from November to March with an average standard deviation of £21/MWh, whereas the lower volatility period ranges from April to October with an average standard deviation of £14/MWh.

The maximum spread between minimum and maximum monthly average power price in a given month is £108/MWh for 2017/18 and £103/MWh for fiscal year 2020/21.

Figure 8 Monthly power price profiles (£/MWh)

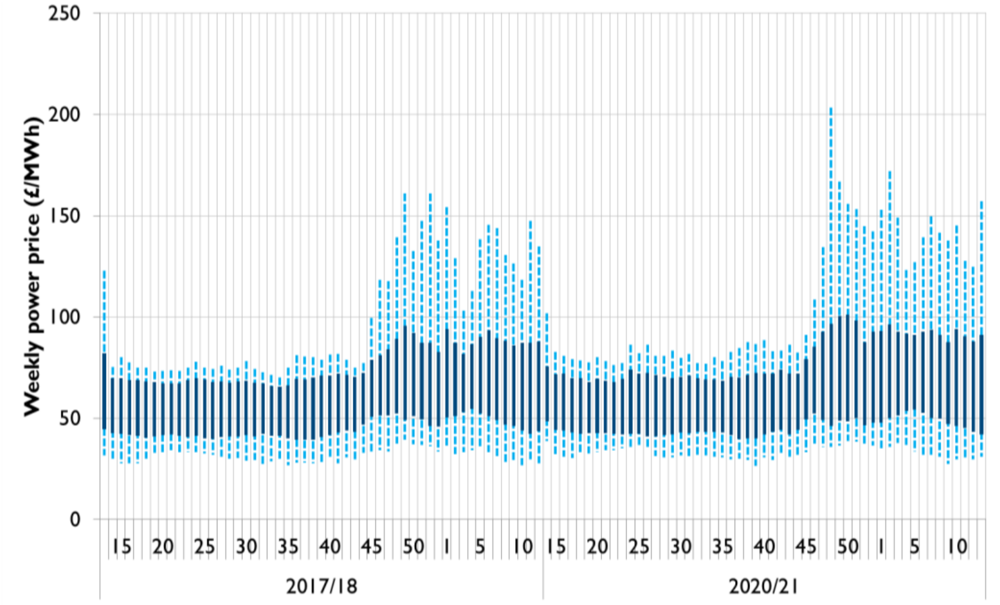


Weekly granularity

Figure 9 shows weekly power price profiles for both fiscal years modelled. The dark blue bar represents prices within one standard deviation of the average weekly price, while the light blue dotted line stretches from minimum to maximum price observed during the week.

The variation in average weekly prices is higher than in average monthly prices due to averaging across fewer periods. The maximum spread between the minimum and maximum price recorded in a given week is £125/MWh in fiscal year 2017/18, and £1678/MWh in 2020/21.

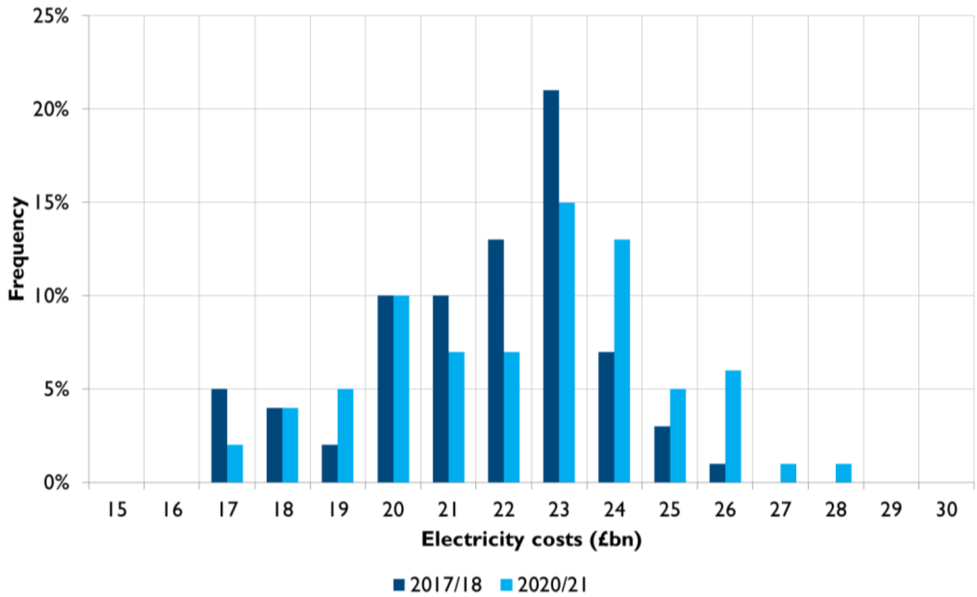
Figure 9 Weekly power price profiles (£/MWh)



3.3. Electricity costs to suppliers

In this section we calculate the total wholesale cost of power for suppliers based on day-ahead hourly prices (i.e. assuming that suppliers purchase their entire supply in the day-ahead market)[30]. This combines the impact of price and demand variations.

Figure 10 Distribution of average electricity costs priced at day-ahead



[30] We did not consider forward hedging in this study.

Figure 10 shows how the wholesale electricity costs are distributed across the 100 Monte Carlo simulations run for each fiscal year. The average cost of purchasing electricity in the day-ahead market is £20bn for fiscal year 2017/18 and £20.6bn in 2020/21. The volatility of electricity costs expressed as a relative standard deviation[31] is 21% for 2017/18 and 22% for 2020/21.

3.4. Generation from CfD generators

One of the key outputs from the power dispatch model is hourly CfD generation for each simulation run. This is particularly important for our study as it is a key driver of CfD payments.

Average annual CfD generation increases from 12.1 TWh in 2017/18 to 36.8 TWh in fiscal year 2020/21. Within these figures, the share of intermittent CfD generation is also increasing from 60% to 67% from 2017/18 to 2020/21.

Figure 11 Monthly average load factors of CfD technologies (fiscal year 2017/18)

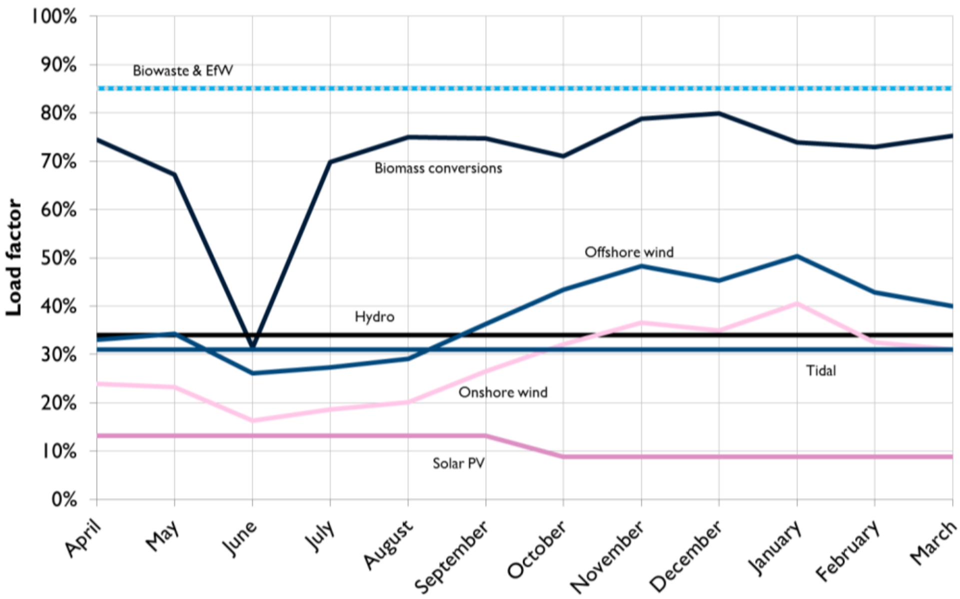


Figure 11 and Figure 12 show the average monthly load factors by technology for the 2017/18 and 2020/21 respectively.

Biomass conversion coal and gas CCS are dispatched based on market conditions. Biomass conversions' running profiles drops in June because the dispatch model schedules maintenance during this period. Similarly, coal and gas CCS have planned maintenance in the first half of April and the end of August/beginning of September respectively. Other monthly variations in biomass and CCS load factors are attributable to forced outages.

[31] This is the ratio of standard deviation to average value.

Figure 12 **Monthly average load factors of CfD technologies (fiscal year 2020/21)**

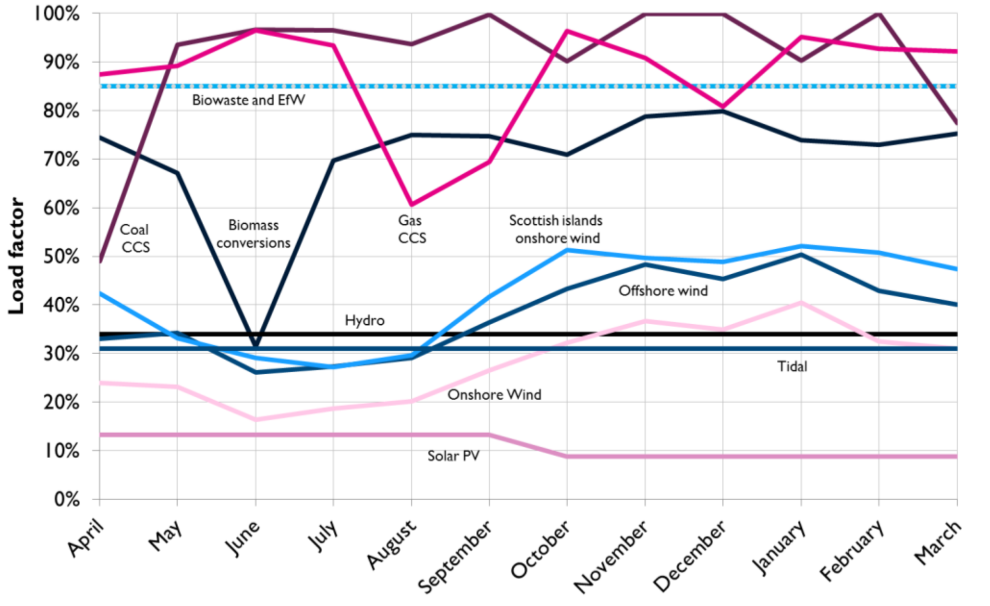
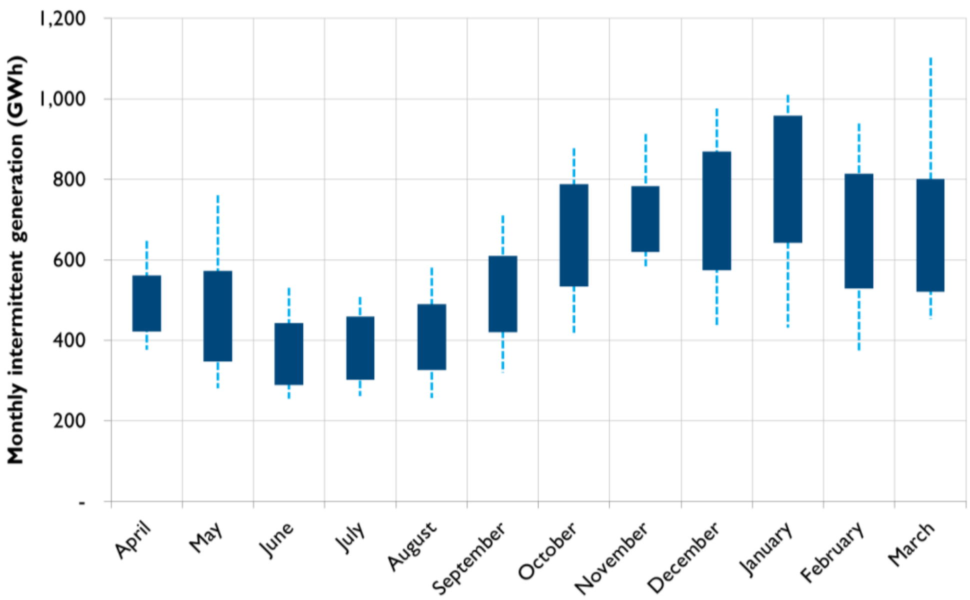


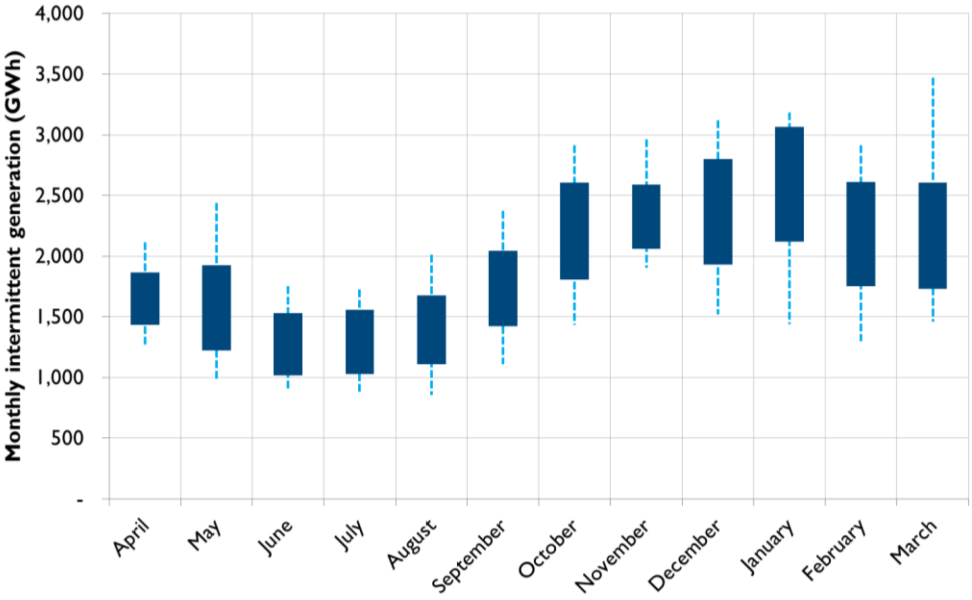
Figure 13 and Figure 14 show the variation in monthly generation of intermittent CfD generators for the two fiscal years studied. The dark blue bars represent generation within one standard deviation of monthly average while the dotted light blue lines stretch from minimum and maximum monthly generation recorded. The two years show similar patterns, although the absolute value of generation is much higher in 2020/21[32]. The range of outcomes is much wider in December through March, when compared to the rest of the year.

Figure 13 **Monthly generation from onshore and offshore wind (fiscal year 2017/18)**



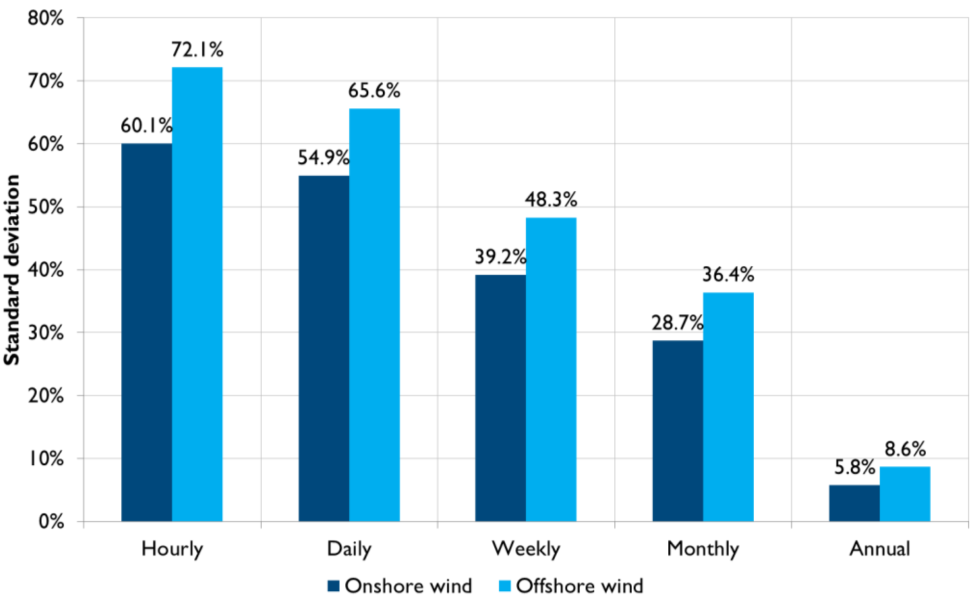
[32] Note difference in y-axis scale between the two charts

Figure 14 **Monthly generation from onshore and offshore wind (fiscal year 2020/21)**



The variability of wind load factor at various timescales is shown in Figure 15. Wind variability is large at the daily level (i.e. two days picked randomly are very likely to have quite different wind load factors), but this variability is considerably reduced when aggregated at an annual level, i.e. forecast errors of annual wind output are likely to be relatively low by comparison[33].

Figure 15 **Relative standard deviation of wind generation on different timescales**



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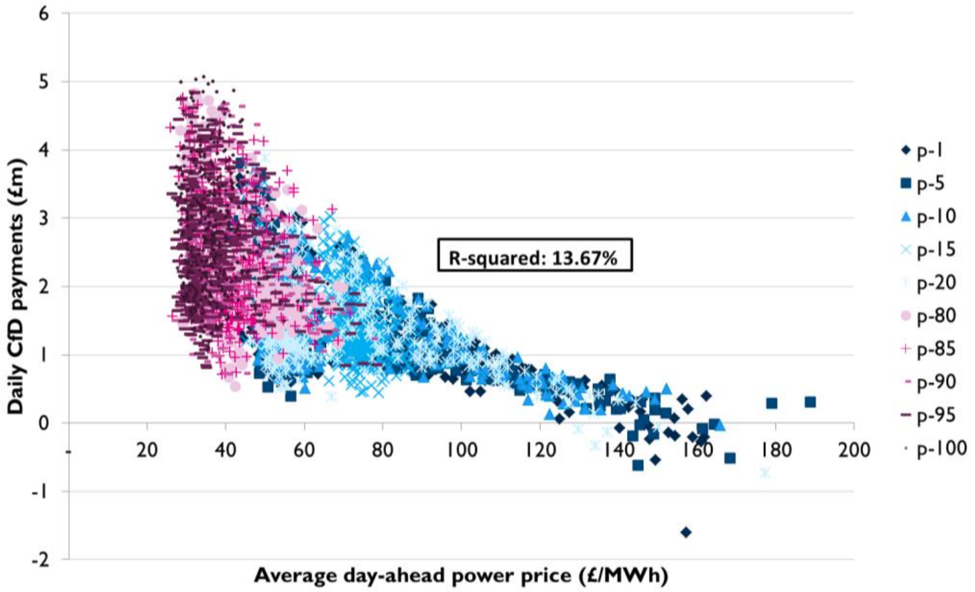
[33] This analysis is based on simulated wind profiles calibrated to 20 years of historical data.

3.5. Payments to CfD generators

In 2017/18, the model forecasts annual CfD payments to average £684m, rising to £2.7bn by fiscal year 2020/21[34], with a relative standard deviation of 23% in 2017/18 and 19% in 20/21. The share of payments to intermittent technologies is similar between 2017/18 (63%) and 2020/21 (61%). Further results are provided in Appendix B.

Market Reference Prices are a key driver of CfD payments. This section describes the relationship between total CfD payments and day-ahead market prices in different simulations, which is relevant to overall supplier exposure. Figure 16 and Figure 17 plot the average day ahead power price against the CfD payment for that day, for each of the 365 days of each simulation, to illustrate the relationship between power prices and CfD payments.

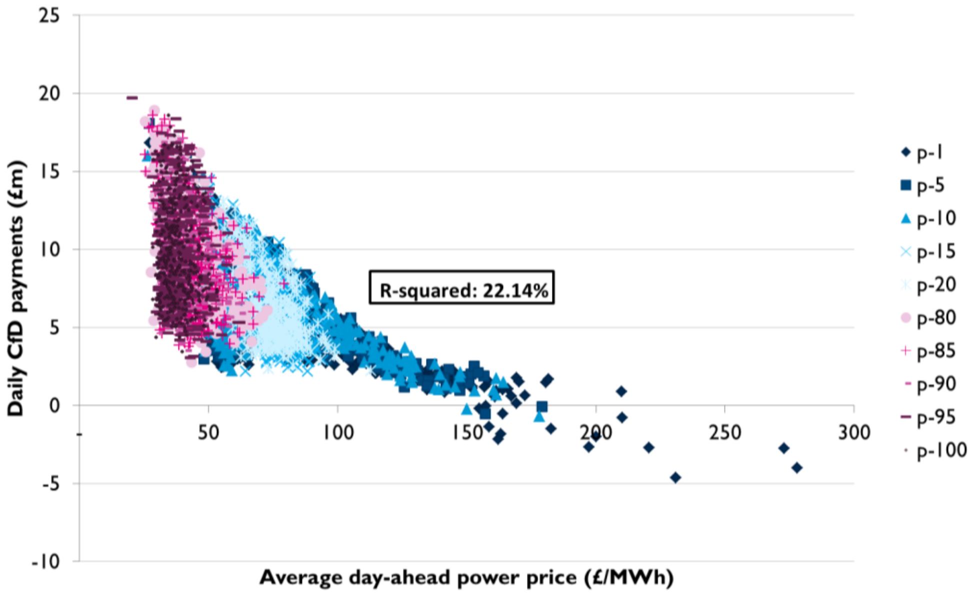
Figure 16 Relating daily CfD payments to average daily power prices (fiscal year 2017/18)



[34] Modelled CfD payments are based on Final Delivery Plan 2013 modelling, and include implicit assumptions on both future capacity mix, and the relative levels of deployment under each LCF support scheme. As these are modelled assumptions, they may be subject to changes in the future and should not be interpreted as the CfD budgets. The CfD budgets will be set by DECC in July 2014.

![Baringa logo]

Figure 17 **Relating daily CfD payments to average daily power prices (fiscal year 2020/21)**



As shown in Figure 16 and Figure 17, at a daily level the model does not show a very tight relationship between daily CfD payments and average day-ahead prices, as evidenced by the R-squared[35] values of 14% in 2017/18 and 22% in 2020/21. This illustrates that on a daily basis variation in CfD generation due to wind variability has a greater effect on CfD payments than variation in price[36]. Variability of daily CfD payments is particularly high when wholesale prices are low, since the higher difference payments magnify the volume variability. We observe a difference of up to £4.5m per day in 2017/18 (240% of average daily payments) due to different levels of wind generation on a very low price day. This figure increases to £15m by 2020/21 (200% of average daily payments) due to the large deployment of offshore wind in particular. In contrast, when wholesale electricity prices are high CfD payments will be low (or even negative at very high prices), so even large fluctuations in CfD generation will have relatively small impacts on CfD payment volatility.

The relatively low standard deviations of annual wind load factors described in Section 3.4 means that the inverse correlation between CfD payments and power prices is much greater when considered at the annual level (Figure 18). Indeed, R-squared indicators are 97% for 2017/18 and 96% for 2020/21, much higher than the figures recorded at the daily level (14% for 2017/18 and 22% for 2020/21). This result illustrates that at the annual level electricity prices are by far the biggest driver of variability in CfD payments, whereas at the daily level output from CfD generators is potentially the biggest driver.

[35] R-squared, which can vary between 0 and 1, is a measure of fit of data points to a statistical model. The higher the R-squared the stronger the relationship.

[36] When all wind plant run at full capacity, modelled power prices do not become negative in most cases.

Figure 18 Relating annual CfD payments to annual average day-ahead power price

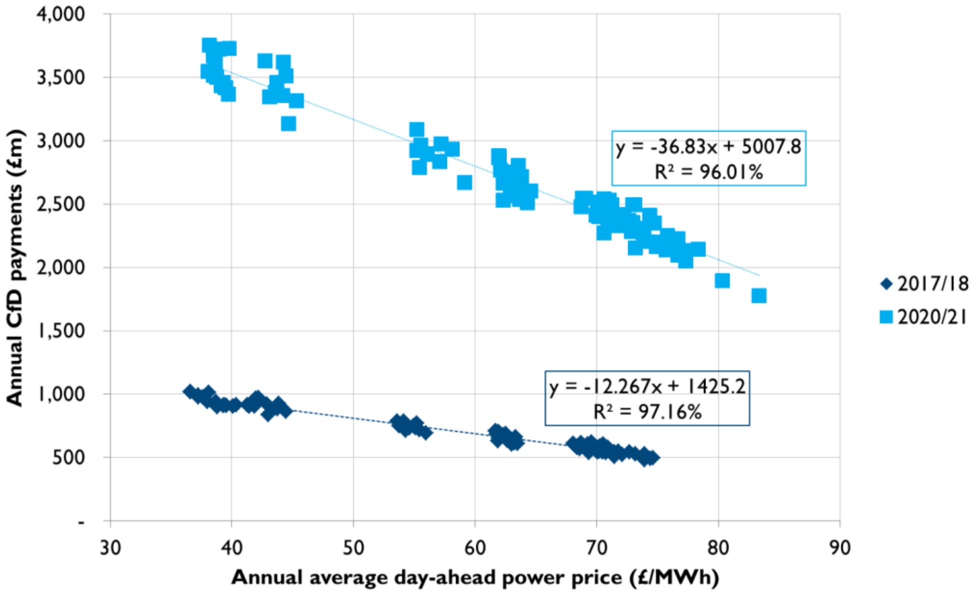
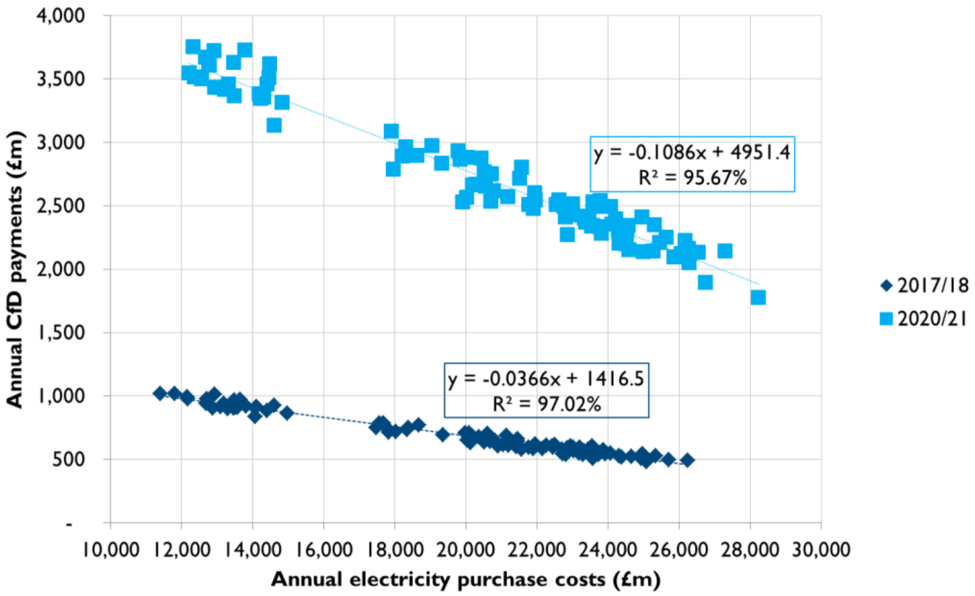


Figure 19 shows similar, although slightly smaller levels of correlation between annual CfD payments and annual electricity purchase costs for suppliers (defined in Section 3.3). R-squared indicators are 97% for 2017/18 and 96% for 2020/21, slightly smaller than the the R-squared values between CfD payments and baseload price[37].

Figure 19 Relating annual CfD payments to annual electricity purchase costs



From a supplier's perspective, supplier payments would be added to the costs of supply volumes to customers. Figure 19 suggests annual CfD payments and annual cost of purchasing electricity to supply it

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[37] The degree of correlation betwee CfD payments and wholesale purchasing costs is slightly lower than between CfD payments and annual wholesale prices because another factor of variability (annual power demand) has been added. The variability of demand is very low (around 2%, cf. Section Demand in Appendix A), which is the reason why the drop in R-squared is very small.

to final consumers are likely to be highly correlated and to move in opposite directions (i.e. when the cost of purchasing electricity is higher than anticipated, supplier payments will be lower and vice versa). This means that the SO could be a hedge against electricity purchasing costs at the annual level (for the share of volume exposed to the SO Levy). However, as the analysis above shows, it would be a very imperfect hedge at the daily level given the variability in CfD generation volumes.

4. ANALYSIS OF POLICY OPTIONS

4.1. Overview

This section presents results of our SO policy analysis. We first compare variability of supplier payments in the Unit Cost Fixed as well as the Fully Variable policy options. We then focus on the Unit Cost Fixed policy option, first calculating the interim rate value (as estimated at the start of each year) and finally assessing the size of the reserve fund and associated financing costs.

4.2. Variability of supplier payments across policy options

Under the SO, suppliers will be required to make payments to the CfD Counterparty. The size of these payments and their variations depend on the SO policy option considered (Unit Cost Fixed or Fully Variable SO Levy). Below we examine the variability of daily payments from suppliers[38] in each of these two policy options.

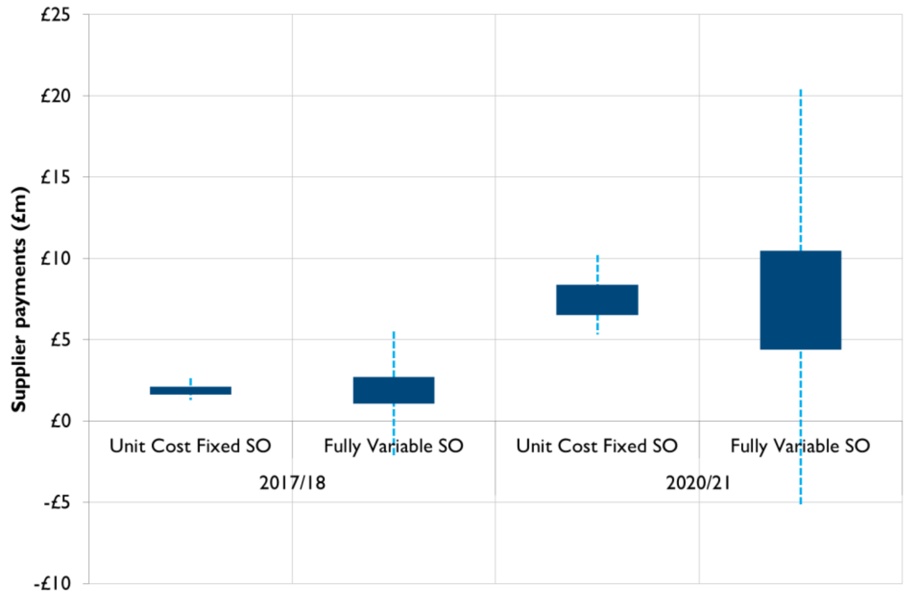
The Unit Cost Fixed and Fully Variable SO policy options propose different methods for calculating daily supplier payments:

- Under the **Unit Cost Fixed** policy the CfD Counterparty forecasts expected Market Reference Prices, volume of CfD generation, and level of demand, and uses this to set a £/MWh interim rate. Suppliers are invoiced on a daily basis according to their daily supply volume.
- Under the **Fully Variable** SO, suppliers are invoiced for their share of actual CfD costs shortly after they are incurred.

Figure 20 presents the standard statistical measures of daily supplier payments variations in fiscal years 2017/18 and 2020/21.

[38] This does not take into account the variability of payments into the RF.

Figure 20 Variability of daily supplier payments (£m)[39]



While the average payment is identical across policy options (£1.9m/day in 2017/18 and £7.4m/day in 2020/21), the variability of these payments is very different across policy options:

- In the **Unit Cost Fixed** case, the relative standard deviation in daily supplier payments is 13%, for both years. The spread between minimum and maximum supplier payments represents 71% of the average value in fiscal year 2017/18 and 65% in 2020/21. The only driver of intra-period variability in daily supplier payments is daily electricity demand, the volatility of which is modest compared to the full volatility of CfD payments. However, this does not take into account the variability of reserve fund or reconciliation payments.
- In the **Fully Variable** policy option, relative standard deviation in daily supplier payments is 44% in 2017/18 and 41% in 2020/21. The difference between the minimum and maximum payments is 412% of the average value in 2017/18, and 344% of the average in 2020/21. Since daily supplier payments track CfD payments in this scenario, suppliers are exposed to the full variability in Market Reference Price and CfD generation volume. In this case, it is possible to see negative supplier payments i.e. CfD generators pay the CfD Counterparty in days when Market Reference Prices are higher than CfD strike prices, and in turn the CfD Counterparty redistributes the money to suppliers[40]. (In the Unit Cost Fixed case, payments from CfD generators to the CfD Counterparty would be reconciled against total payments at the end of the Levy period.)

After considering the payments in the reserve fund under the Unit Cost Fixed option, the volatility in total supplier payments on an annual basis will be similar between the two options, although the timing of payments within year will be very different.

Figure 21 and Figure 22 compare the full distribution of daily supplier payments in the two policy options for fiscal years 2017/18 and 2020/21 respectively. Although the average payment increases over time, the

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[39] The dark blue bars represent SO payments within one standard deviation of daily average while the dotted light blue lines stretch from minimum and maximum daily SO payments recorded.

[40] Under this policy, the CfD Counterparty would make payments to suppliers only once it has received the money from generators. Our modelling does not reflect this.

variation increases in line with it such that the shape of the distributions remains relatively similar across both fiscal years modelled.

Figure 21 **Distribution of daily supplier payments (fiscal year 2017/18)**

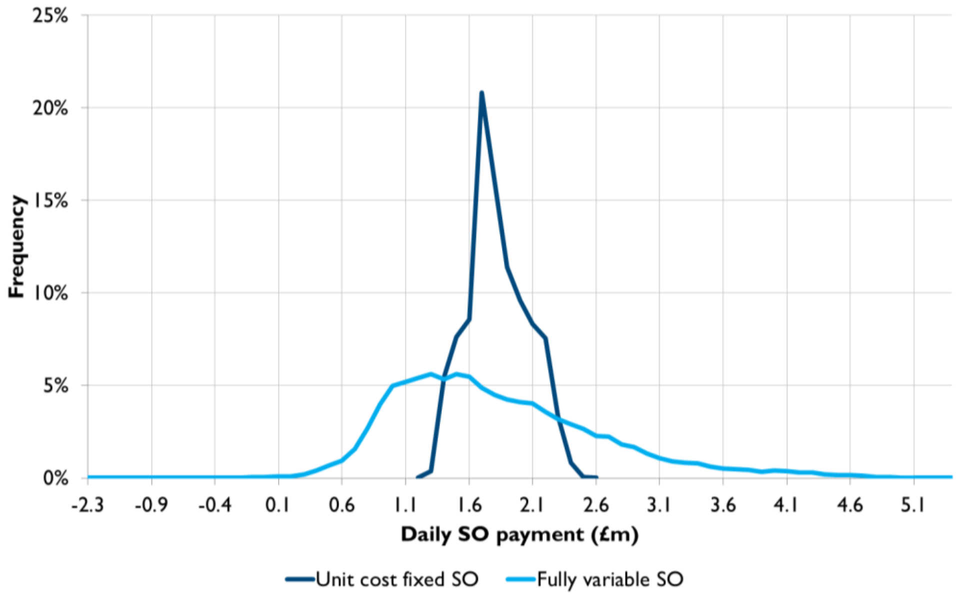
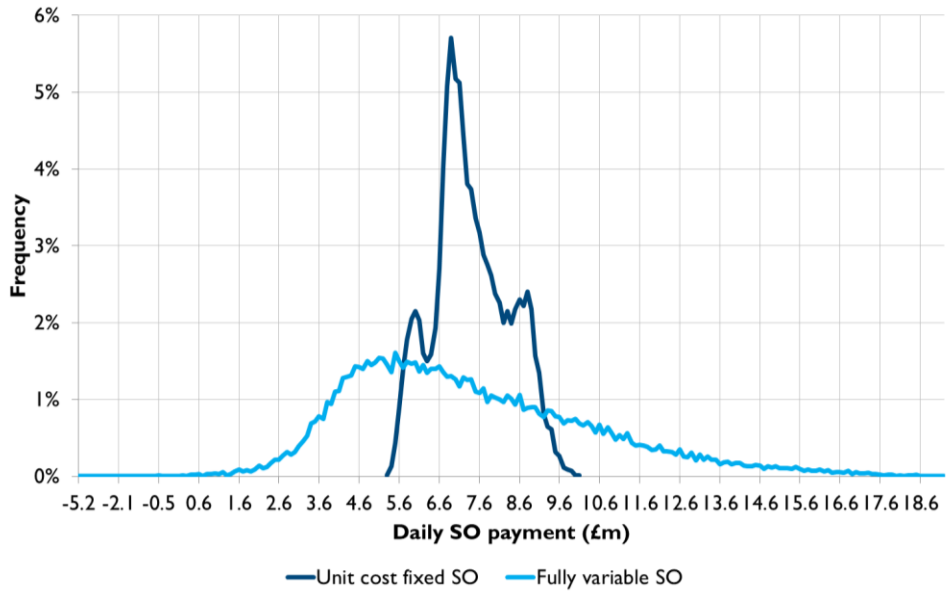


Figure 22 **Distribution of daily supplier payments (fiscal year 2020/21)**



4.3. Supplier payments analysis across SO settlement periods in the Fully Variable option

Under the Fully Variable policy, suppliers will be exposed to the daily volatility in CfD payments. We have explored the impact on the volatility of payments of changing the settlement period from daily to weekly or monthly. First, we examine supplier payments variability on an annual basis, and then look at monthly and weekly variations.

Annual variability

Table 3 shows supplier payments aggregated on an annual basis for the two fiscal years considered. Average annual supplier payments are £684m in 2017/18 and increase to £2.7bn in 2020/21. In the p-95 case[41], annual supplier payments increase to £976m in 2017/18 and £3.6bn in 2020/21[42]. Although standard deviations increase in absolute terms from £157m in 2017/18 to £506m in 2020/21, the relative standard deviation decreases from 23% to 19%.

Table 3 Annual supplier payments

Supplier payments (£m)	2017/18	2020/21
Average	684	2,715
p-95 case	976	3,630
Standard deviation	157	506
Standard Deviation as % of average	23%	19%

Monthly variability

The average monthly supplier payment is £57m in 2017/18. The volatility of these monthly payments averages 27%, compared with 23% with annual payments. In 2020/21, the average monthly SO Levy payment is £226m and the volatility averages 23% (19% for annual payments).

Weekly variability

The average weekly SO Levy payment is £12.9m[43] in 2017/18. The volatility of these weekly payments, expressed by the relative standard deviation, averages 32%, compared with 27% with monthly payments. In 2020/21, the average weekly SO Levy payment is £51.2m[44] and the volatility averages 29% (compared to 23% for monthly payments).In both fiscal years, switching from monthly to weekly payments would increase the standard deviation by 5 to 6 percentage points. Figure 23 summarises the reduction of volatility of supplier payments across daily, weekly, monthly settlement periods as well as on an annual basis. The figures for daily settlement are equivalent to CfD payments (Section 3.5), since these are the same values separated only by a payment delay.

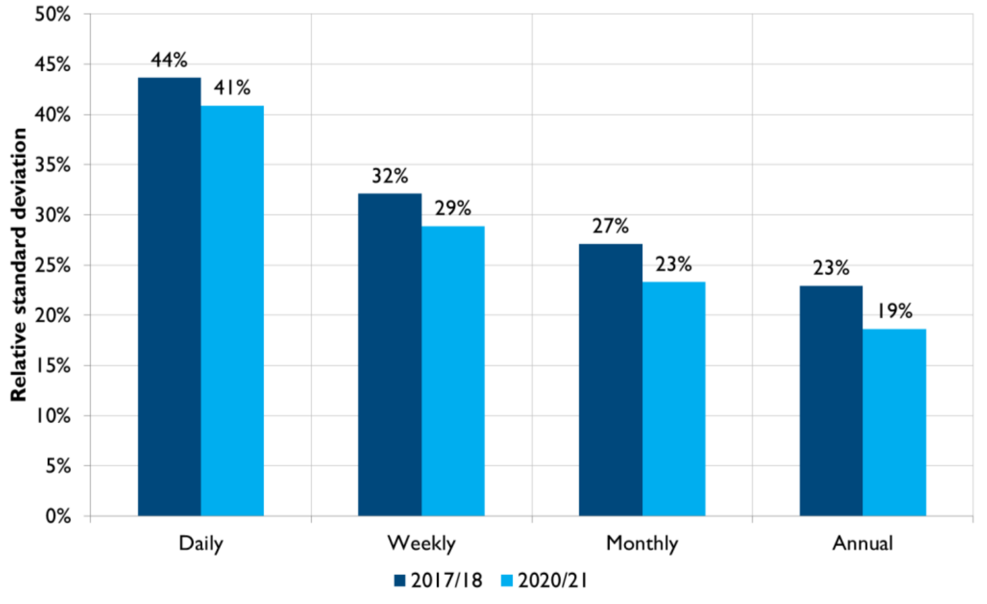
[41] i.e. the 6th highest annual SO payments from our 100 simulations

[42] The difference between SO payments in the p-95 and the average cases does not exactly match p-95 reserve fund figures because the p-95 case for SO payments is different from the p-95 case for reserve fund (annual demand is not taken into account for just SO payments).

[43] The average weekly payment is slightly less than seven times the daily payment of £1.9m because of incomplete weeks at the beginning and end of the year.

[44] The average weekly payment is slightly less than seven times the daily payment of £7.4m because of incomplete weeks at the beginning and end of the year.

Figure 23 Volatility of supplier payments across various timeframes



4.4. Unit Cost Fixed analysis

4.4.1. Interim rate levy

Under the Unit Cost Fixed policy option, suppliers pay a £/MWh interim rate, with actual daily payments determined by daily electricity demand. In our modelling, this interim rate is defined as the ratio of average annual CfD payments to average annual GB electricity demand (i.e., it is assumed that the averages from all simulations represent the CfD Counterparty's forecast for CfD payments and demand), and is set for the entire duration of the fiscal year, three months in advance[45]. These values are £2.1/MWh in 2017/18 and £8.3/MWh in 2020/21.

In this policy option, the CfD Counterparty would be required to hold a reserve fund paid by suppliers to manage cash flow volatility due to uncertainty in outturn Market Reference Prices, CfD generation and electricity demand. While the average costs of CfDs will be recouped through the interim rate, the reserve fund is defined as the additional amount of money necessary to cover CfD payments in situations where CfD payments are higher than expected (e.g. due to higher CfD generation or lower reference prices), or demand is lower. The reserve fund would be set at a level to enable the CfD Counterparty to be able to meet CfD payments up to a specified level of confidence (e.g. p-95[46]).

We first explain how simulated evolutions of the CfD Counterparty's cash position throughout the fiscal year help determine the size of the reserve fund and then describe the financing costs under the three funding mechanisms outlined in Section 1.2.

[45] Note that under the final policy set out by DECC, the interim rate would be set on a quarterly rather than an annual basis.

[46] P-statistics are calculated by ranking values (e.g. reserve fund size here) in order of decreasing favourability (e.g. larger CfD payments or reserve fund size are worse than smaller ones). For instance, a p-95 reserve fund size is the 6th largest reserve fund size in our 100 simulations. Clearly this analysis cannot capture risks we have not modelled and therefore this represents a 5% confidence level within the narrow bounds of the model definition.

4.4.2. Reserve fund analysis

In the cash flow model, we calculate the CfD Counterparty's cash position at the end of each day in the fiscal year by summing payments due from suppliers (based on the interim rate multiplied by electricity demand) and to (and from) CfD generators (based on the strike price minus Market Reference Price multiplied by CfD generation), taking into account the timing of the payments. This gives the evolution of the CfD Counterparty's cash position throughout the fiscal year for each simulation run. We rank these simulations annually by decreasing order of favourability for the CfD Counterparty, i.e. the most favourable case (p-1) is the one where the CfD Counterparty's cash position at period end is the highest (i.e. payments received from suppliers through the year have been greater than those made to generators) and the least favourable case (p-100) is the one where the CfD Counterparty's cash position within the period is lowest (payments to generators exceeded those received from suppliers). Figure 24 shows the CfD Counterparty's cash position evolution throughout the course of the fiscal year 2017/18 in various cases: "favourable" cases (p-1, p-5 and p-10) and "unfavourable" cases (p-90, p-95 and p-99). The modelled CfD Counterparty's final cash position at the end of the 2017/18 fiscal year can be positive: £228m (p-1), £189m (p-5), and £171m (p-10) as well as negative: - £223m (p-90), - £275m (p-95), - £330m (p-99).

Figure 24 CfD Counterparty's cash position evolution under various cases (fiscal year 2017/18)

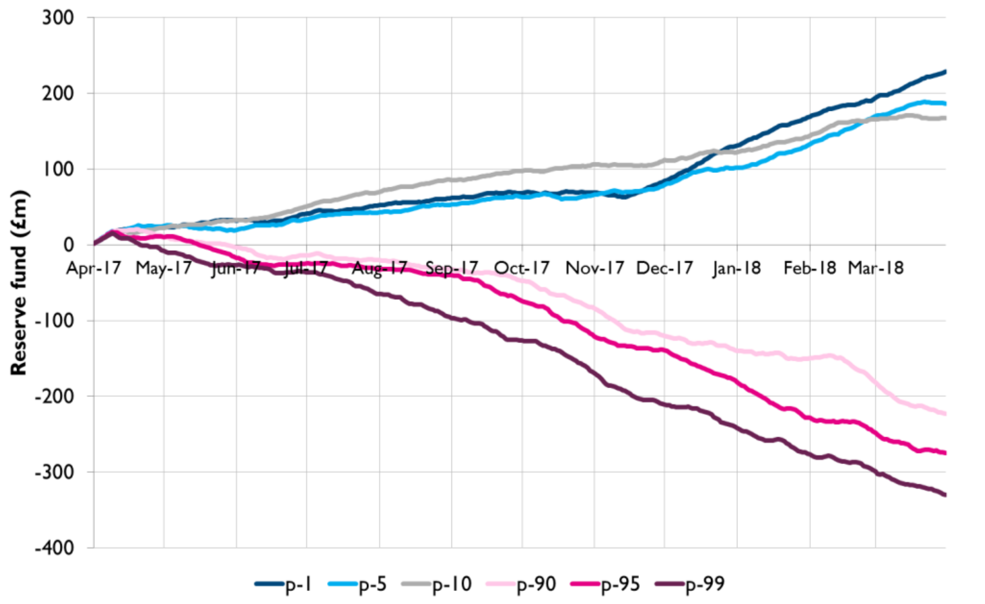
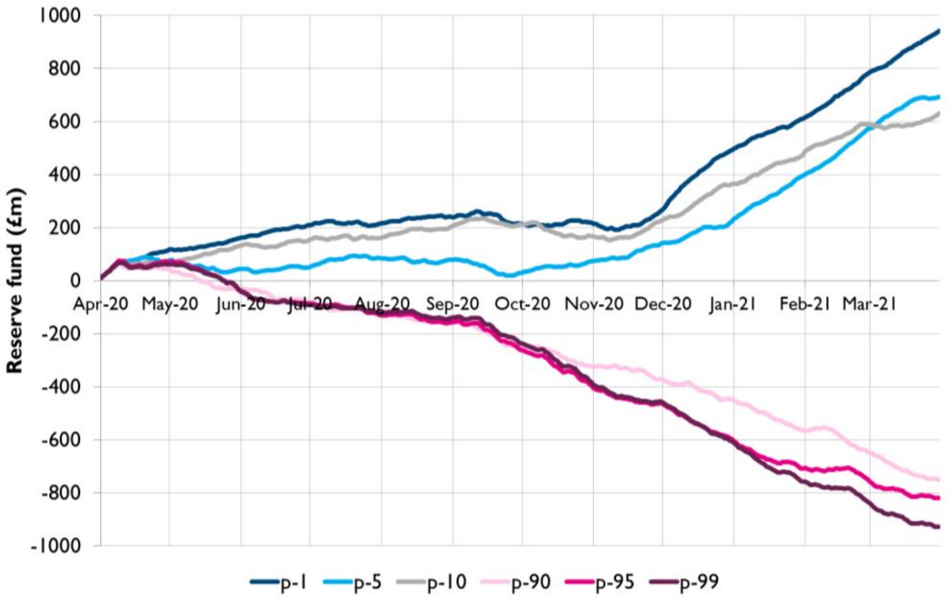


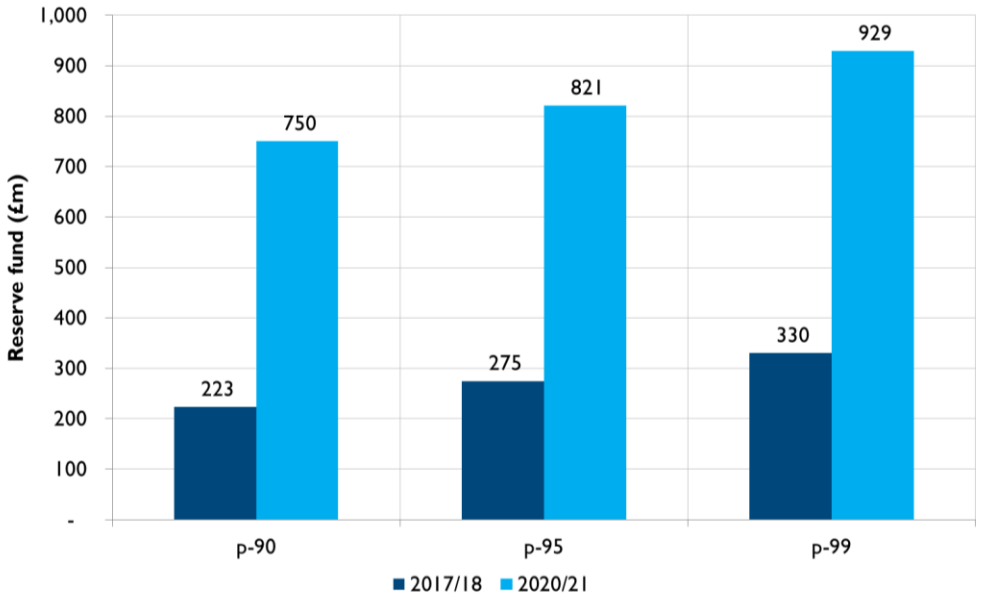
Figure 25 shows the CfD Counterparty's cash position evolution throughout the course of the fiscal year 2020/21 in the same cases. The simulated CfD Counterparty's final cash position at the end of the 2020/21 can be positive: £942m (p-1), £694m (p-5), and £630m (p-10) as well as negative: - £750m (p-90), - £821m (p-95), - £929m (p-99).

Figure 25 **CfD Counterparty's cash position evolution under various cases (fiscal year 2020/21)**



The reserve fund requirement is based on additional cash requirements in the least favourable outcomes, i.e. it is the amount the CfD Counterparty would need to hold to ensure its cash position never becomes negative. Figure 26 shows the annual reserve fund needed for p-90, p-95 and p-99 cases for both fiscal years considered here. This means the CfD Counterparty would require £275m in 2017/18 and £821m in 2020/21 in order to cover the risk of CfD payments in 95% of modelled outcomes. If the reserve fund was set only to cover the risk of 90% of modelled outcomes, the reserve fund size would drop by £52m in 2017/18 and by £71m in 2020/21.

Figure 26 **Reserve fund requirements under various p-scenarios**



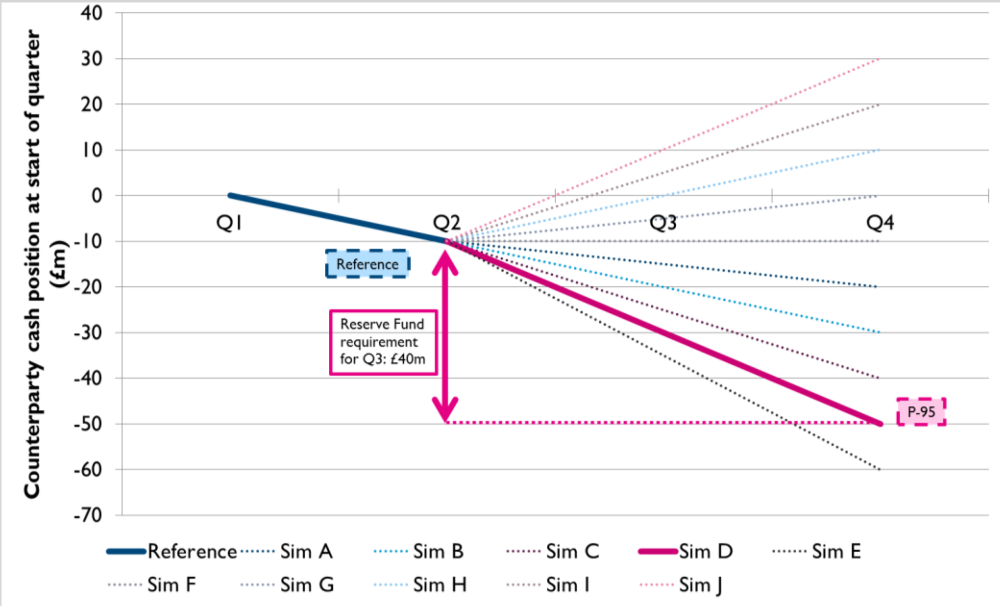
We have modelled three different funding mechanisms for the RF, focusing on the p-95 case. The results are:

- **Annual**: under this option, suppliers would pay the reserve fund in full (£275m in 2017/18 and £821m in 2020/21) in one lump sum at the start of the fiscal year. Following the annual reconciliation process the reserve fund would be back to its starting level. In subsequent years additional funds would be requested as the reserve fund requirement increases in line with increasing CfD generation (and expectations of Market Reference Prices may have changed).
- **Staged Quarterly**: under this option, the total amount of the reserve fund is determined at the start of the year but suppliers are only required to pay at the start of each quarter the amount that is estimated (at the start of the year) to be required in that quarter. This way, suppliers will be invoiced for the same amount of money over the year as under the Annual option, but the staging of payments will reduce financing costs associated with providing the funds. In both years, over 80% of the reserve fund is required during the winter. This is partly due to the fact that forecasts are made in the previous November and therefore there is greater time for deviation to occur. However, there are also two fundamental factors that mean winter reserve fund should be expected to be higher. First, periods of highest wind generation occur in winter, and when these combine with low power prices they generate the highest levels of CfD payments. Second, power prices are more volatile in winter than in summer and therefore there is a greater range of outcomes. Under this approach the reserve fund requirement fluctuates through the year peaking in the final quarter. Following the annual reset of the interim rate and reconciliation, the reserve fund requirement reduces again.
- **Quarterly Fixed**: under this option, the CfD Counterparty makes a new estimate for the size of the reserve fund each quarter three months in advance, taking into account the additional information available and the CfD Counterparty's cash position at the point it sets the reserve fund (see Box 1). This reduces the expected size of the RF, since it is unlikely that the full amount of the reserve fund will have been used in each quarter. In our modelling, the first two quarterly instalments are equal to the ones in the Staged Quarterly case since the reserve fund requirement for these quarters is calculated prior to the start of the Levy period, and we have not assumed any re-forecasting on the part of the CfD Counterparty (which would reduce the reserve fund requirement in practice). For Q3 and Q4 the CfD Counterparty may have a positive cash balance (unless the p-95 case occurred during Q1 and Q2) and hence we assume that on average this reduces the reserve fund requirement in the subsequent quarters. As with the Staged Quarterly approach, the reserve fund requirement fluctuates through the year peaking in the final quarter, and reduces again following the annual reset of the interim rate and reconciliation. An illustrative worked example of Quarterly Fixed reserve fund requirements for Q3 is presented in Box 1.

Box 1 Calculation of Quarterly Fixed reserve fund

The calculation of payments into the reserve fund under the Quarterly Fixed option differs in that the reserve fund payments are not set at the start of the year, but rather evolve as more information becomes available. To illustrate this, we consider an example where the CfD Counterparty's cash position drops £10m during Q1 ('Reference' curve in Figure 27): this is covered by the £10m reserve fund for Q1. At the beginning of Q2, the CfD Counterparty receives another £10m as reserve fund for Q2 (both the Q1 and Q2 values are set before the start of the year). The CfD Counterparty then needs to assess the reserve fund required for Q3 i.e. the amount needed to cover CfD payments until the end of Q3 within a 95% confidence interval. To do this, it generates a range of possible outcomes over the next six months. Ten of these outcomes are represented in Figure 27 below as Sim A through J. The p-95 case ('Sim D' curve in Figure 27) predicts a further drop of £40m during the next 6 months (i.e. until the end of Q3). The existing reserve fund for Q2 will cover £10m of this requirement therefore the CfD Counterparty will request a further £30m from suppliers to make up the reserve fund for Q3.

Figure 27 **Quarterly Fixed reserve fund mechanism for Q3**



We note that this differs from full quarterly reconciliation as proposed by DECC, under which the reserve fund and interim rate would be reset each quarter, using updated forecasts. Under this approach, there would be no difference in treatment between Q1 & Q2 and Q3 & Q4.

Figure 28 summarises the reserve fund requirements in a p-95 case for each funding mechanism considered for fiscal year 2017/18. Under the Staged Quarterly approach, the total reserve fund requirement by Q4 is the same as under the Annual approach (£275m), but payments have been staged. Under the Quarterly Fixed approach the increment payments for Q3 and Q4 are lower and the annual reserve fund requirement averages £197m, i.e. 28% less than the Annual or Staged Quarterly options.

Figure 28 **p-95 reserve fund requirements under various funding mechanisms (fiscal year 2017/18)**

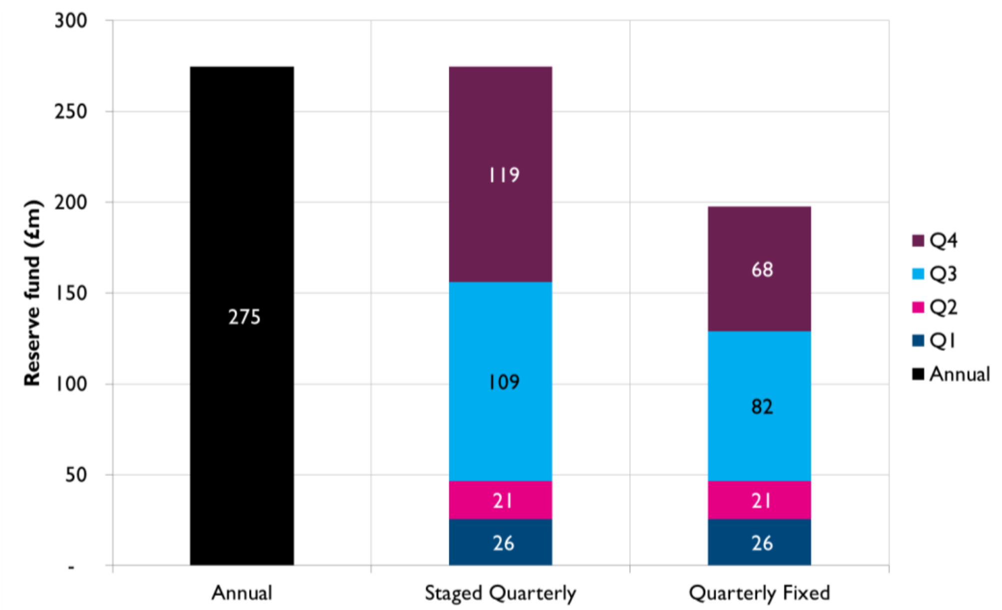
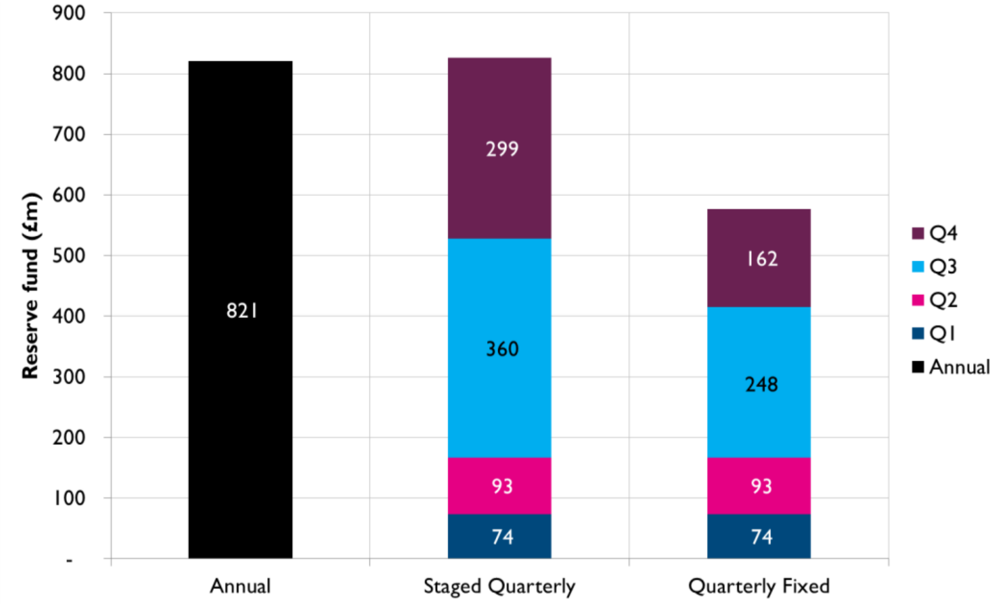


Figure 29 summarises reserve fund requirements in a p-95 case for each funding mechanism considered for fiscal year 2020/21. The annual reserve fund requirement under the Quarterly Fixed approach is on average £577m (i.e. 30% lower than the Annual or Staged Quarterly approaches).

Figure 29 p-95 reserve fund requirements under various funding mechanisms (fiscal year 2020/21)



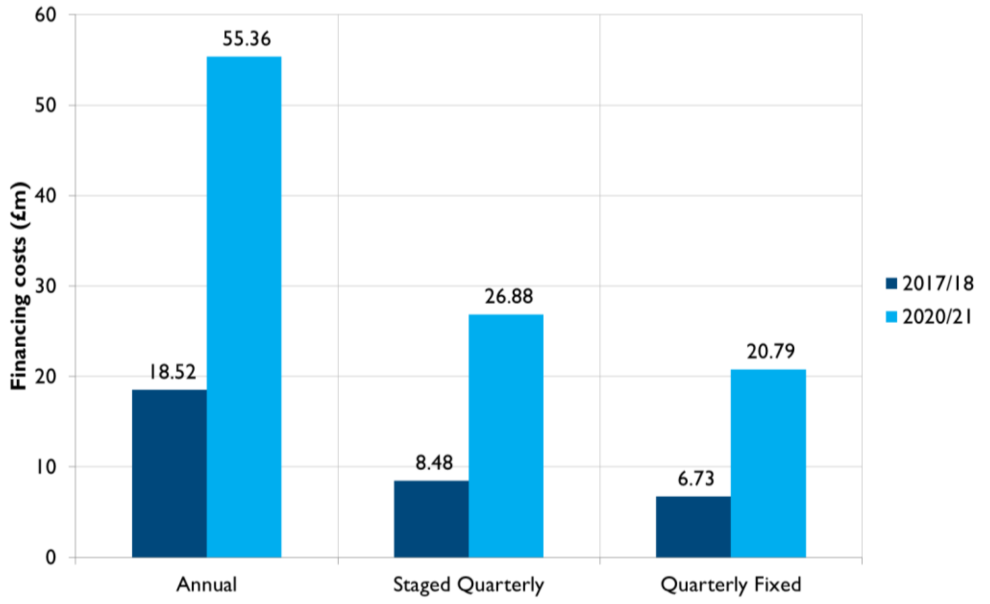
The reserve fund requirements under DECC's updated policy proposal for quarterly interim rate resets, and reconciliation, would be lower again. The analysis in this report preceded the updated policy position. In a p-95 scenario, suppliers would still need to make the same level of payments as described in the Staged Quarterly option through the reconciliation mechanism. Under DECC's updated proposal, reforecasting CfD payments each quarter will allow for a more accurate setting of the interim rate and further reduce the size of the reserve fund (albeit with greater uncertainty in the interim rate).

4.4.3. Financing costs analysis

Suppliers would be required to pay into a cash fund so that the CfD Counterparty can manage cash flow volatility due to uncertainty of CfD payments and electricity demand. On average, by the end of the Levy period the reserve fund should not have been depleted. Under the annual funding mechanism, suppliers would finance the full reserve fund amount for the whole fiscal year whereas under Staged Quarterly and Quarterly Fixed funding mechanisms only the amount due for the first quarter would have to be financed over the full year, the amount required for the second quarter would be financed over the last three quarters of the year and so forth. We have assumed a cost of capital of 6.744%[47]. The resulting reserve fund financing cost in a p-95 case for each funding mechanism is shown in Figure 30.

[47] Source: SO Impact Assessment October 2013

Figure 30 **Costs of financing the reserve fund in the Unit Cost Fixed option (p-95 case)**



We note that switching from Annual to Staged Quarterly payments decreases financing costs by 54% in 2017/18 and 51% in 2020/21. Switching from Staged Quarterly to Quarterly Fixed financing method would further save 27% in 2017/18 and 26% in 2020/21 (reductions of 64% and 62% from the annual financing costs in 2017/18 and 2020/21 respectively).

4.5. Summary of policy option results

The analysis demonstrates the range of variation in CfD payments to generators that might be expected on an annual and daily basis, considering the impact of variability in gas prices, wind generation and demand. Our modelling of the Fully Variable and Unit Cost Fixed SO options demonstrates that these approaches change the timing and volatility of payments to the CfD Counterparty. Under both options the risk of CfD payments in total being higher or lower than expected over the course of the year ultimately remains with suppliers.

- The **Fully Variable** option puts the onus entirely on suppliers to manage the variability associated with day-to-day CfD payments, and to make the necessary provisions. The extent to which this results in additional funding costs to suppliers would depend on how their wider hedging and pricing strategies adapted to a Fully Variable SO Levy. The variability of supplier payments decreases when settlement frequency decreases (e.g. daily, weekly and monthly).
- Under the **Unit Cost Fixed** option, the variability is largely managed centrally, but suppliers must pay into a reserve fund to act as a buffer so that the CfD Counterparty can manage CfD variability.

Under the Unit Cost Fixed SO option, the interim rate set for the full fiscal year would be £2.1/MWh in 2017/18 and £8.3/MWh in 2020/21, and the annual reserve fund required can be set to cover several levels of risk:

- In 2017/18, the annual p-95 reserve fund is £275m (i.e. 40% of modelled average CfD payments) with a 20% range from p-90 to p-99. Under Quarterly Fixed funding option, the average annual reserve fund is reduced to £197m (29% of modelled average CfD payments).

- In 2020/21, the annual p-95 reserve fund is £821m (i.e. 30% of modelled average CfD payments) with a 10-15% range from p-90 to p-99. Under the Quarterly Fixed funding option, the average annual reserve fund is reduced to £577m (29% of modelled average CfD payments).

Three funding methods for recouping this cash reserve fund from suppliers have been modelled. Their associated financing costs in a p-95 case are:

- **Annual**: £18.5m in 2017/18 and £55.4m for 2020/21;
- **Staged Quarterly**: £8.5m in 2017/18 and £26.9m for 2020/21; and
- **Quarterly Fixed**: £6.7m in 2017/18 and £20.8m for 2020/21.

Appendix A Power dispatch modelling approach

Introduction

Our modelling approach closely replicates the way in which the power market operates. For this, we use PLEXOS for Power Systems, a generation dispatch model, to determine market prices. This model is discussed in more detail below.

Dispatch model

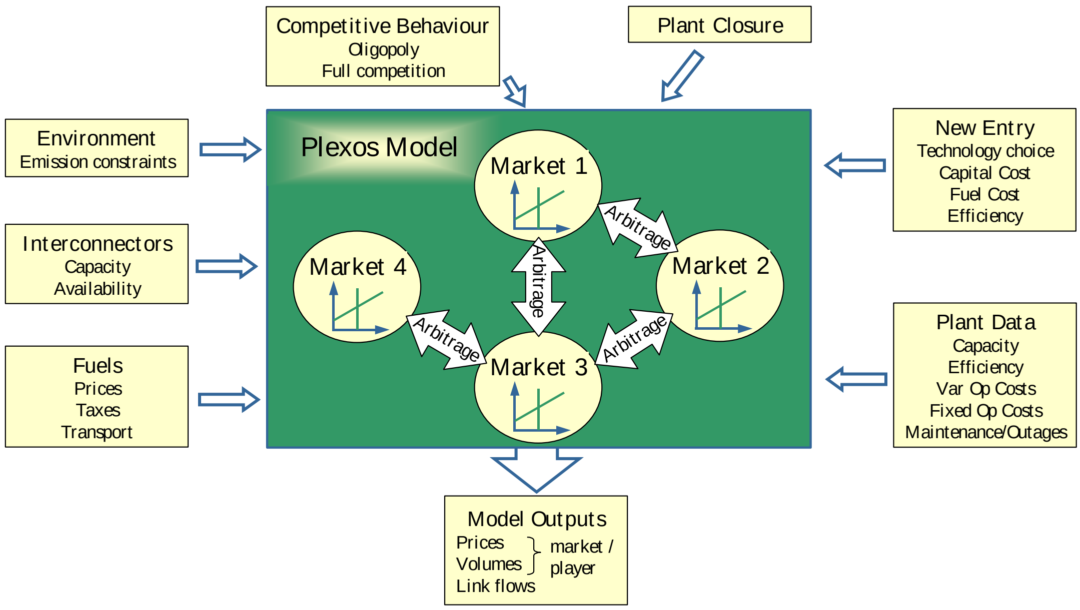
a) PLEXOS overview

PLEXOS is an advanced market modelling tool, incorporating a number of approaches to the modelling of interconnected markets, and a number of advanced pricing algorithms ranging from marginal cost pricing through to game-theory approaches. It is deployed worldwide by energy companies, investors and system operators.

PLEXOS simulations are based on a mathematical programming formulation of power market dynamics. PLEXOS applies linear and mixed integer programming solution techniques to determine the dispatch and pricing outcomes, taking full account of short term dynamic constraints including ramp rates and min on/off times. This approach provides results that fully capture the complexity of power markets and allows the user to analyse fundamental issues such as nodal pricing, hydro modelling, profit targeting and strategic behaviour.

An overview of the model is shown in Figure 31.

Figure 31 PLEXOS Overview



b) Demand

Demand is fully represented at hourly granularity. Hence, there are 8,760 settlement periods per year. Demand is modelled on a station gate (sent out) basis i.e. including transmission and distribution losses.

c) Plant constraints

All thermal plant on the system are modelled with annual maintenance rates and forced outage rates. The scheduling of maintenance is through a Monte Carlo approach to determine an optimal scheduling, whilst outage patterns are applied randomly.

d) Hydro modelling

The reservoir hydro units have a limited monthly energy profile, and the model will dispatch this energy according to prices within the month. The profile is kept constant for each river system over the scenario period.

Pumped storage plant will operate based on the day-night price differential and subject to the technical constraints of the plant (pumped load, pumping efficiency and head and tail storage capacity).

e) Interconnection

The model contains a simplified representation of the GB, Irish and continental markets. The model will simultaneously optimise across all markets in a single step. This ensures that the operation of each market is consistent and that the flows through the two interconnectors represent the most economically efficient solution.

f) Price formation

The model aims to dispatch plant in such a way that generation costs are minimised over each optimisation horizon (24 hours). Each generator has a multi-part heat rate curve. This is comprised of a no-load cost, and a number of incremental heat rates which apply over different tranches of the generator's capacity. The shadow price is calculated based on SRMCs; set by the incremental heat rate of the marginal generator including the full pass through of the prevailing spot fuel and spot EUA (carbon) prices including CPF.

The calculation of the outturn prices includes a calculation of uplift: an uplift component is added in each period to ensure that each generator recovers its start-up and no-load costs (i.e. is 'made whole') over the period in which it operates, while another uplift component is added to represent a scarcity premium. Hence, in each hour the model derives a marginal cost, an uplift payment and market price.

In summary, electricity price results from the dispatch model are influenced by:

- **Short run marginal costs** (SRMC) of generating electricity from all power plant bidding in the market: power price is based on the highest running cost of all operating generators;
- **Price of electricity in interconnected markets**: imports can be substituted to additional generation if they are cheaper; and
- **Capacity margin**, which is the available capacity standing ready to respond to a demand increase: the uplift corresponding to scarcity premium is a function of the capacity margin.

Dispatch inputs

a) Load factor and maintenance

Some CfD-supported electricity generation technologies are assumed to follow a regular running pattern:

- **Biowaste** and **EfW** are modelled as baseload generators with 15% maintenance rate, including scheduled maintenance and forced outages;

- **Hydro** (representing run-of-river) and **tidal** generators will run as perfect baseload generators throughout the year with 34% and 31% load factors respectively; and
- **Solar PV** is represented in the dispatch model as a baseload generator during the day, while they are effectively shut down at night. Their annual load factor is set to 11%.

Table 4 recaps load factors used for all fixed-load-factor CfD-supported technologies.

Table 4 CfD technologies load factors[48]

Technology name	Annual net load factors
Biowaste	85%
Energy from Waste (EfW)	85%
Hydro	34%
Solar	11%
Tidal	31%

Power plant scheduled maintenance and forced outages are configured using our standard set of assumptions for the GB market.

b) Stochastic inputs

The following sections detail the methods used to generate stochastic simulations. The dispatch model will run using a set of stochastic inputs: gas price, wind profiles and demand. They are combined together to form 100 simulations as:

- For **gas prices** and **electricity demand**, we provide 100 profiles to the dispatch model, which it can randomly sample between; and
- For **wind**, the dispatch model uses a set of 20 wind profiles sequentially: i.e. simulation #1 uses wind profile #1, simulation #20 uses wind profiles #20, simulation #21 uses wind profile #1 and so on.

In the following sections, we will detail the methodologies used to simulate these stochastic parameters.

Gas prices

We used a natural gas price simulation model based on an Ornstein-Uhlenbeck process with a Brownian motion and a mean reverting drift, as shown in Equation 2. This model allows us to calculate the evolution of gas price one step at a time: i.e. we determine the price on day 1, we use this result to calculate price the next day and so on.

Equation 2 Gas price simulation model

$$\Delta p_t = \alpha * (\mu - p_t) * \Delta t + \sigma * dz_t$$

Where:

- Δp_t is the step change of the logarithm of the gas price from time t to time t+1;

[48] These values are consistent with DECC's internal assumptions and National Grid report for the final Delivery Plan (Annex D, p64). It can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

- p_t is the logarithm of the gas price at time t (in practice, there is only one price per day);
- $\alpha * (\mu - p_t) * \Delta t$ is the mean-reversion term, α is the annual mean-reversion rate, and μ is the monthly average price of gas. In practice, in order to avoid a lagging effect in the simulation, we use a smoother version of this monthly average where we taper in new monthly average price over 12 days; and
- $\sigma * dz_t$ is the Brownian motion term, σ being the seasonal volatility and dz_t being a normal distribution of mean zero and standard deviation $\sqrt{\Delta t}$.

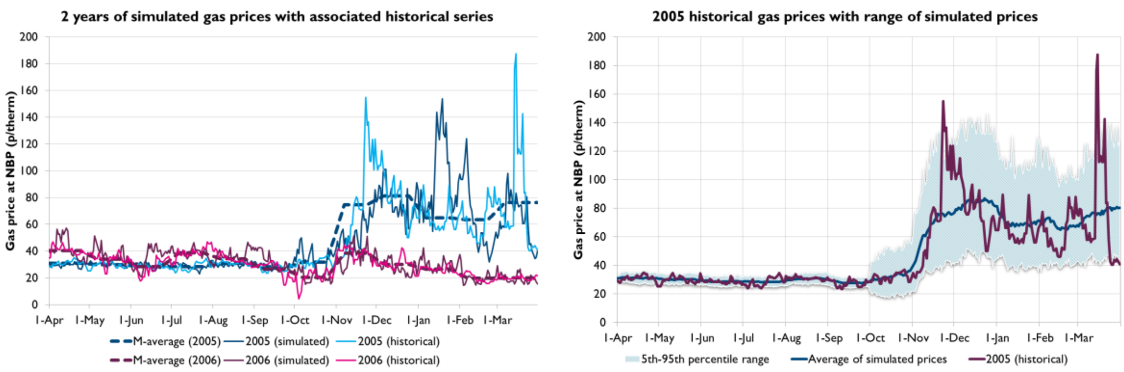
This model is calibrated using eight fiscal years of GB natural gas prices: from 2005/06 to 2012/13 (source: Platts). For each of these years, we evaluate:

- One mean-reversion coefficient;
- One series of monthly average prices with 12-day smoothing period; and
- Two seasonal volatility coefficients (winter and summer).

To generate a simulated price curve, we randomly select a base year from the eight historical years to derive all parameters required to run the simulation model. We compare historical and simulated prices to check the model is well calibrated.

In Figure 32 (left), we present how simulated prices relate to historical prices and the smoothed monthly average curve for fiscal years 2005/06 and 2006/07. Figure 32 (right) also shows the variability obtained using this price simulation process in the case of an extreme year (fiscal year 2005/06) which saw price spikes to 187.50 p/therm.

Figure 32 Comparing simulated and historical gas prices



Once prices are output from the simulation tool, we need to post-process them so that they:

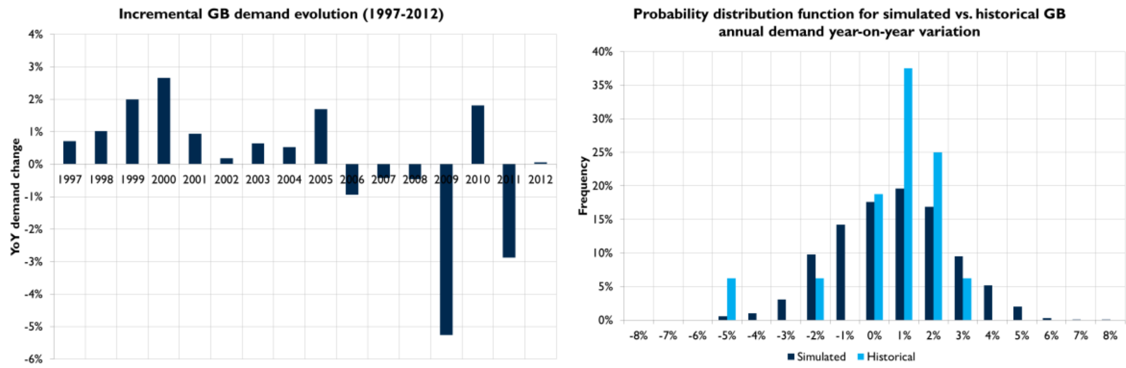
- Reflect historical forward premium/discount from November for delivery next fiscal year; and
- Can be scaled to DECC UEP numbers for the years studied here: 2017/18 and 2020/21.

Demand

We modelled various electricity demand profiles using the following framework:

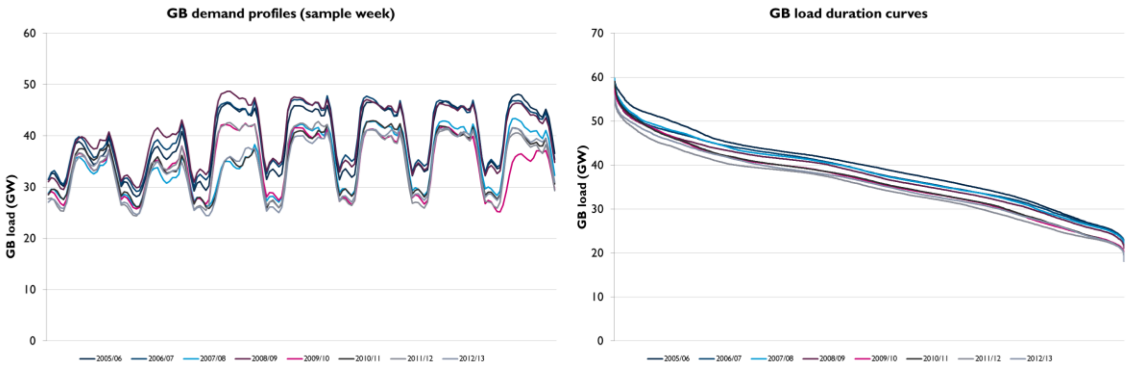
- Annual demand is assumed to follow a normal distribution function, centred on DECC's UEP forecast and with a standard deviation calibrated on historical year-on-year changes (1.95%). We used demand figures published by DUKES in order to calculate year-on-year relative demand changes as plotted in Figure 33 (left), we then assessed the fit to a normal distribution, as simulated (right).

Figure 33 GB electricity actual vs. simulated demand changes year-on year



- Demand profile is based on historical load profile from 8 historical fiscal years (2005/06-2012/13). Figure 34 shows two important indicators of these demand profiles:
  - A comparable sample week (left), to review daily demand shape
  - Annual load duration curve (right), to assess the average difference between base years' load.

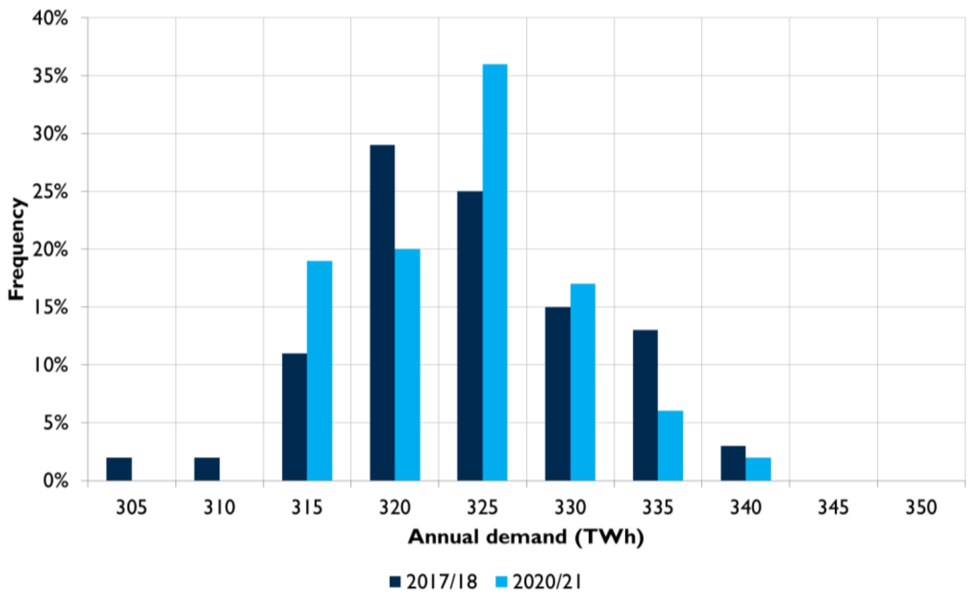
Figure 34 Characteristics of GB demand base years



- 104[49] simulated demand profiles are obtained by drawing an annual demand figure from the calibrated normal distribution as explained above and combining it to one of the eight historical shapes. Figure 35 allows us to visualise the distribution of simulated annual demand across both fiscal years modelled (2017/18 and 2020/21).

[49] We use 104 simulated demand profiles so that PLEXOS can sample between 13 full sets, each containing all of the eight historical shapes.

Figure 35 Distribution of simulated annual demand (2017/18 and 2020/21)



Wind profiles

We used a database of historical wind speed (Wind Atlas) in order to create simulations of wind generation for several wind regions. We focused on nine regions to model deployment of wind assets across the GB market:

- **Onshore wind regions**: England, Wales, South Scotland, North Scotland, Orkney and Shetlands, Western Isles; and
- **Offshore wind regions**: East Anglia, North Sea, Irish Sea.

Since the data we use originates from historical weather analysis, wind speeds are correlated between regions as happened historically.

We recreated wind generation from these wind speed profiles using a typical wind output curve. We can then scale these output numbers such that they match DECC expectations of annual wind load factors as displayed in Table 5.

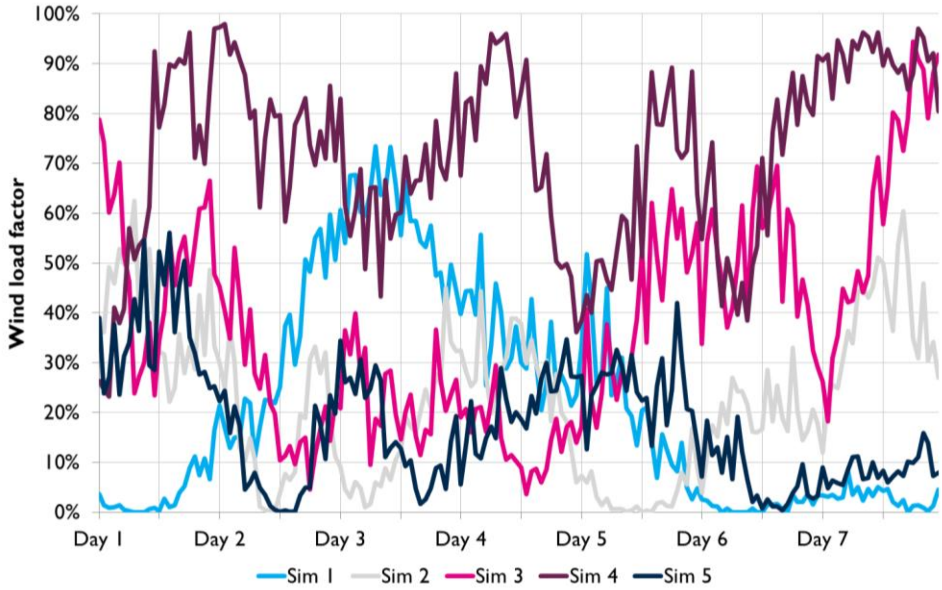
Table 5 Wind annual target load factors by region[50]

Wind region	Annual target load factor
Onshore wind (main island)	28%
All offshore wind	38%
Orkney/Shetland onshore wind	43%
Western Isles onshore wind	35%

[50] These values are consistent with DECC's internal assumptions and National Grid report for the final Delivery Plan (Annex D, p64). It can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

We use a statistical model to convert historical data, provided on a 3-hourly basis to simulated data on an hourly basis. This introduces calibrated random variation in wind speeds such that 3-hourly averages remain constant. Figure 36 shows five simulations of onshore wind load factors in England based on five different historical years, so as to evaluate variability of hourly wind output over a sample week.

Figure 36 England onshore wind output variation (sample week)



In the final model, we chose to include wind output simulations based on the latest 20 years of data. The same 20 simulated wind profiles for each region will be loaded onto each dispatch model, in the same order, such that each historical base year will be represented five times in the 100 simulations.

Appendix B Additional results

Monthly payments to intermittent technologies

Figure 37 shows the range of monthly payments to intermittent CfD technologies for 2017/18.

Figure 37 Monthly CfD payments to intermittent technologies (fiscal year 2017/18)

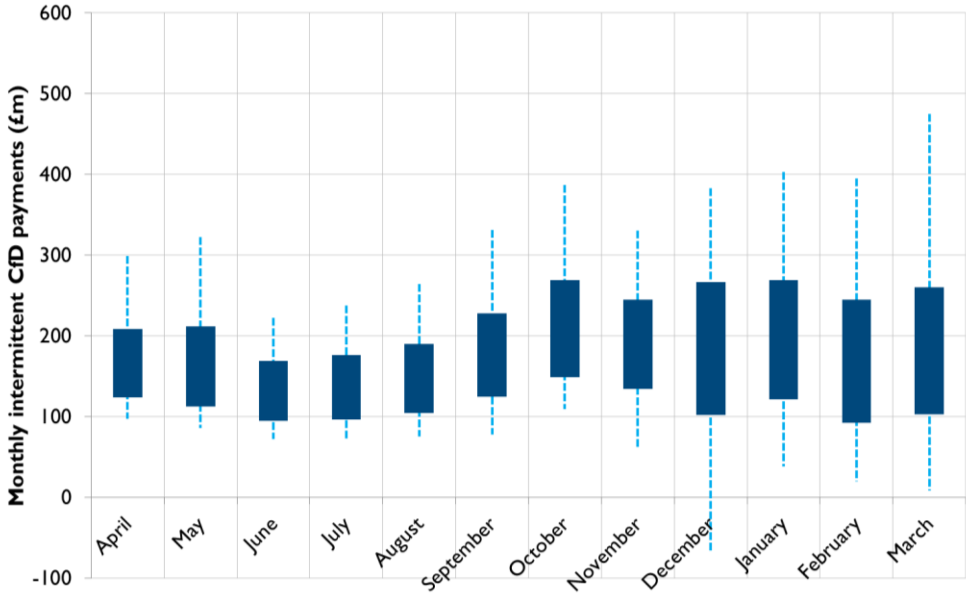
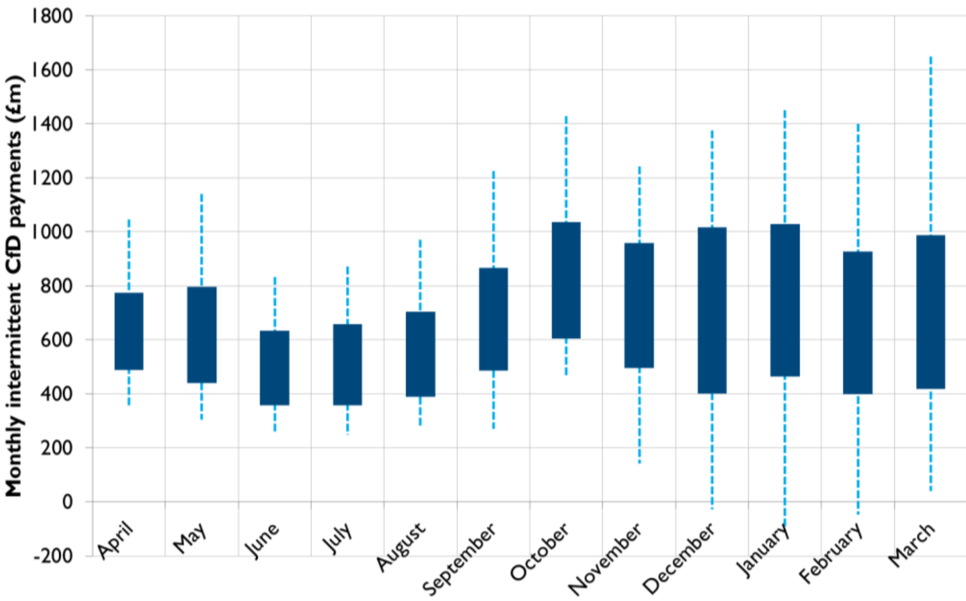


Figure 38 shows the range of monthly payments to intermittent CfD technologies for 2020/21.

Figure 38 Monthly CfD payments to intermittent technologies (fiscal year 2020/21)



Variability of supplier payments

Figure 39 shows the volatility observed in supplier payments settled weekly in 2017/18, under the Fully Variable option.

Figure 39 Variability of weekly SO settlements[51] (fiscal year 2017/18)

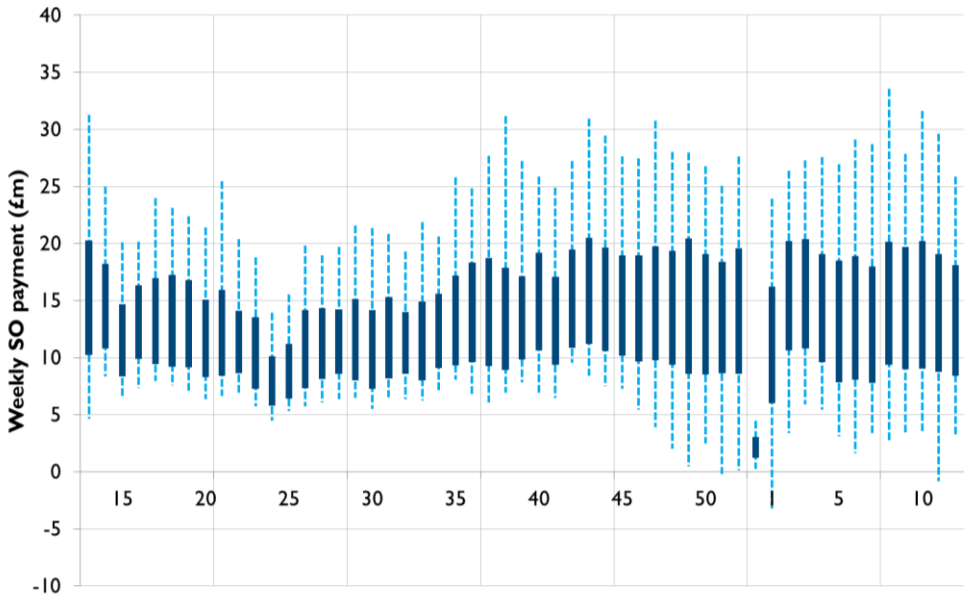
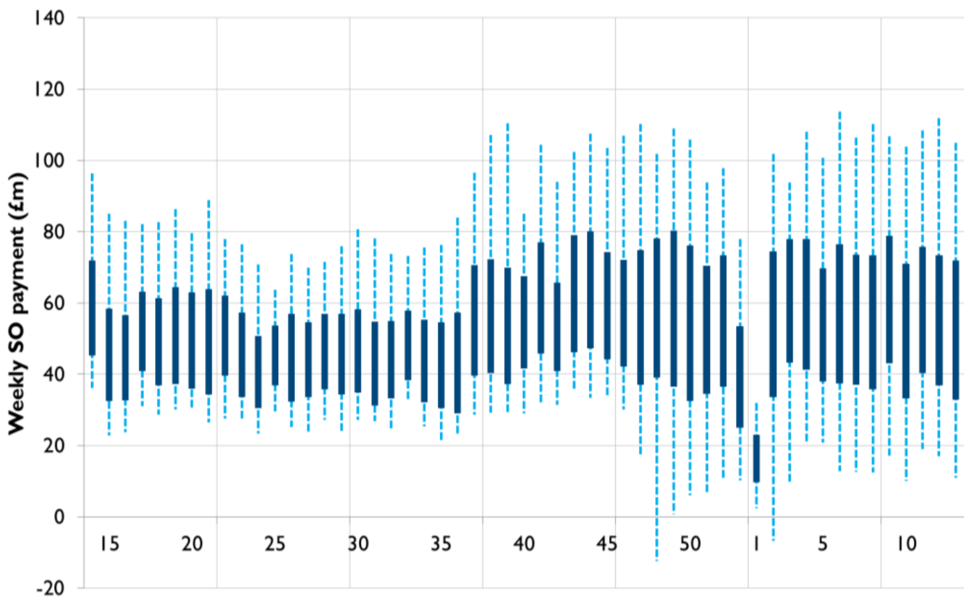


Figure 40 represents variability of SO weekly payments in 2020/21, under the Fully Variable option.

Figure 40 Variability of weekly SO settlements (fiscal year 2020/21)



[51] The first and last weeks of the calendar year comprise fewer than seven days. This is why the average weekly payments during these weeks are much smaller than for the other weeks.

Figure 41 shows the volatility observed in monthly settlements in 2017/18, under the Fully Variable option.

Figure 41 Variability of monthly SO settlements (fiscal year 2017/18)

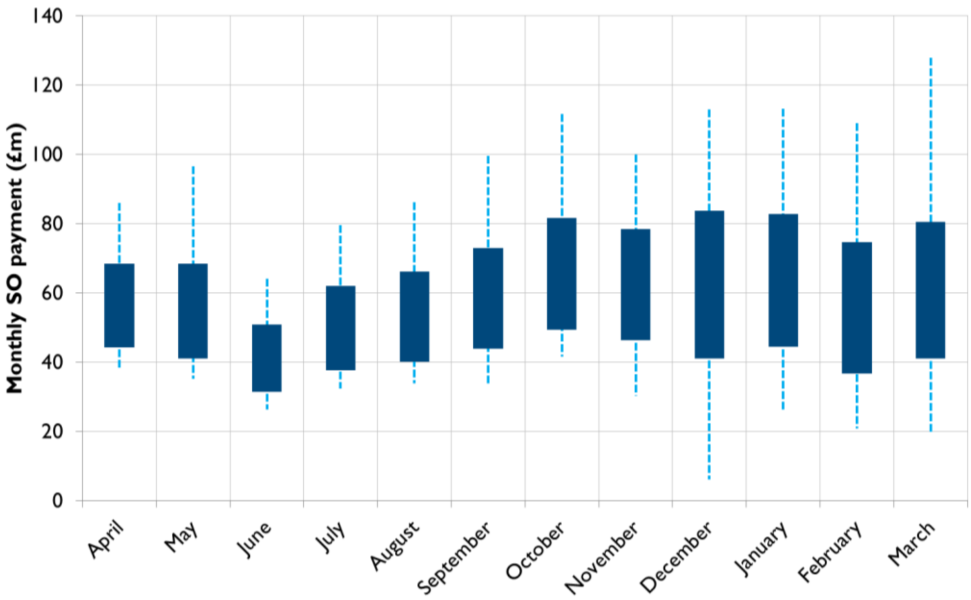
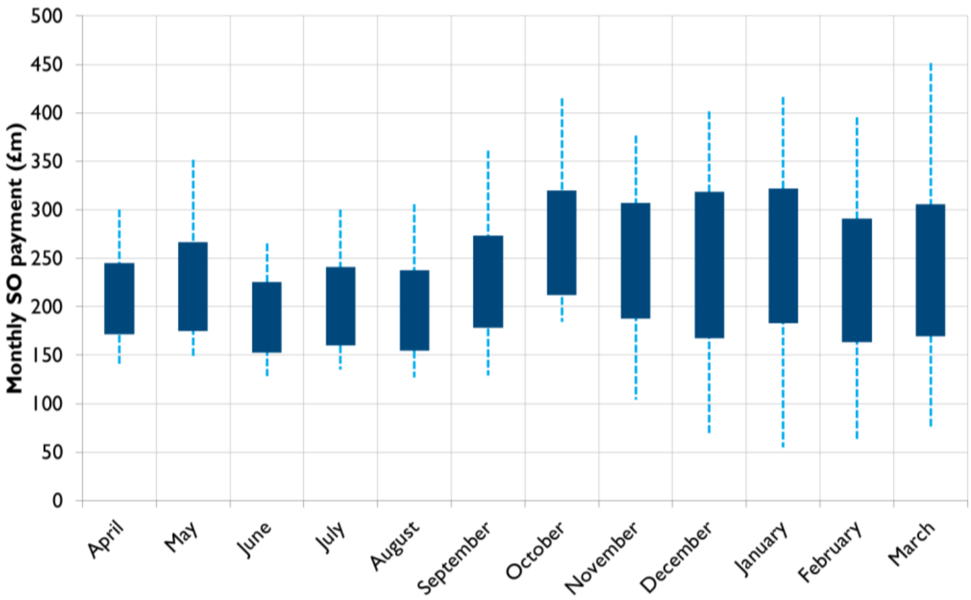


Figure 42 represents variability of SO monthly settlements in 2020/21, under the Fully Variable option.

Figure 42 Variability of monthly SO settlements (fiscal year 2020/21)



Appendix C Glossary of terms

CCS: Carbon Capture and Storage

CfD: Contracts for Difference. This is a mechanism to incentivise the development of low carbon electricity generation by transferring long term wholesale price risk from generators to suppliers, with the intention of reducing the risks associated with the investment.

CfD Counterparty: The organisation responsible for making CfD payments to supported generators as well as receiving supplier payments from suppliers.

CPF: Carbon Price Floor. The mechanism which sets out a trajectory for a minimum level of carbon price in the UK, using a variable annual Carbon Price Support level to bring the cost of EU Allowances up to the floor price.

DECC: Department of Energy and Climate Change

EfW: Energy from Waste

EMR: Electricity Market Reform

GBP: Great Britain Pounds

LCF: Levy Control Framework

RF: Reserve fund

RO: Renewables Obligation. This policy requires suppliers to source a specified portion of the electricity supplied from renewable sources, or pay a buy-out price.

SO: Supplier Obligation. A levy on electricity suppliers to pay for the costs of supporting low carbon electricity generation through CfDs.

SRMC: Short run marginal costs of generating electricity