Department for
Energy Security
& Net Zero

Contracts for Difference

Methodology used to set Administrative Strike Prices for CfD Allocation Round 6

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Introduction

This document explains the methodology for determining the Contracts for Difference (CfD) Administrative Strike Prices (ASPs) for Allocation Round 6 (AR6). ASPs represent the maximum price per MWh price for generating electricity – known as the strike price – that a project of a particular technology type can receive. Should an auction be triggered, ASPs limit the maximum price that projects of a particular technology type can receive, even if the auction clears at a higher price.

Following stakeholder feedback, this methodology note provides more detail on how ASPs are set to improve transparency. This note provides more background information on our broad approach, which is largely consistent with previous allocation rounds. It details what assumption changes have been made to ensure that our evidence base aligns with the current uncertain macroeconomic environment to reflect a sustainable price level at which renewable projects can deliver. The level of granularity in this note should help improve understanding of the Department's approach to setting ASPs. For subsequent rounds, we intend to build from this note to ensure that changes to key assumptions or our approach are thoroughly communicated.

The ASPs included in the Core Parameters publication[1] are presented in Table 1 (below). A single ASP applies across each technology's applicable delivery years.

[1] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-6-core-parameters

Table 1: Administrative Strike Prices (£/MWh in 2012 prices)

Pot	Applicable Delivery Years	Technology Type	**Administrative Strike Price** (applicable in each delivery year)
1	2026/27, 2027/28	**Energy from Waste with CHP**	181
		Hydro (>5MW and <50MW)	102
		Landfill Gas	69
		Onshore Wind (>5MW)	64
		Remote Island Wind (>5MW)	64
		Sewage Gas	162
		Solar PV (>5MW)	61
2	2027/28, 2028/29	**ACT**	210
		Anaerobic Digestion (>5MW)	144
		Dedicated Biomass with CHP	179
		Floating Offshore Wind	176
		Geothermal	157
		Tidal Stream	261
		Wave	257
3	2027/28, 2028/29	**Offshore Wind**	73

Section 1: Objectives for setting ASPs

The ASPs are the maximum price, presented on a price per MWh basis, that the Department is willing to offer developers for each technology type. This is otherwise known as the reserve price. Should there be sufficient bidders for an auction to be triggered, the price paid to successful projects – the clearing price – is set by the bid made by the last project allocated a contract before the auction closes, subject to no project receiving a higher strike price than its technology-specific ASP[2].

The Department identified several policy objectives at the outset of the scheme which frame our approach to setting ASPs. For this allocation round the Department has set ASPs using the same principles and overall analytical framework for ensuring value for money as in previous allocation rounds.

Objectives for setting ASPs

1. **Based on robust cost information.** ASPs should draw on the latest generation cost data, while also considering market conditions, policy considerations, and other technology-specific factors to ensure value-for-money for consumers.
2. **Set to encourage participation in the allocation round.** ASPs should be set at the minimum level necessary to encourage new investment from a significant proportion of the supply curve.
3. **Set using an approach which ensures value for money and is consistent with Government policy and deployment ambitions.** In general, the methodology for ASPs should take a consistent approach across all technologies. However, different sections of estimated supply curves may be targeted to improve value for money and/or ensure consistency with wider ambitions on decarbonisation, and to derive secondary benefits such as innovation and investment, where there is a clear rationale for doing so.

In addition to the objectives above, the Department aims to ensure that ASPs do not overly constrain participation in AR6. Rising costs in the sector would make this more likely all else being equal, so this note sets out how across several factors less conversative assumptions have been made, and our evidence base updated, to reflect this ambition. ASPs continue to serve an important role in protecting consumers from high costs, as well as other auction design factors which will be published in due course.

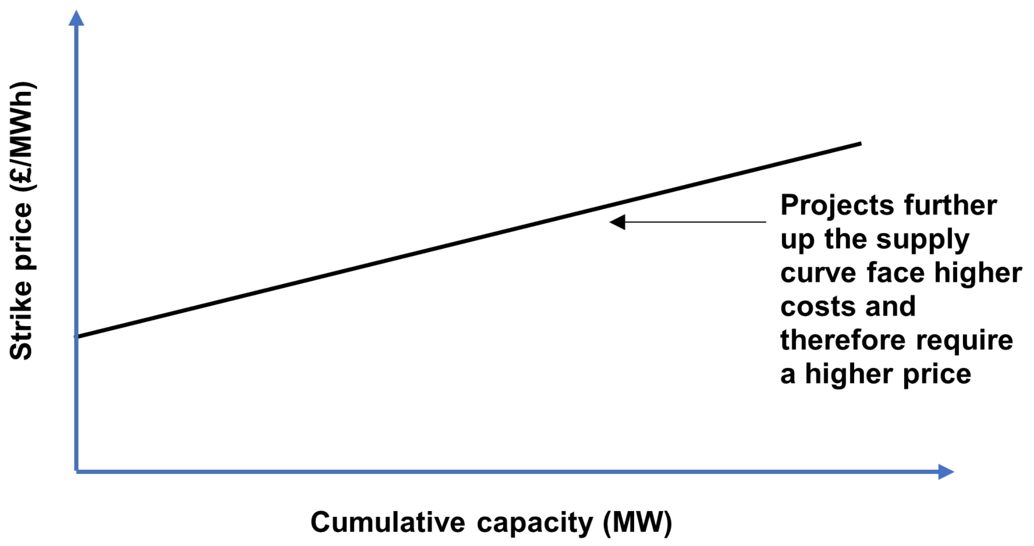
[2] Technologies subject to a maximum set their own clearing price (see the Allocation Framework for more detail).

Section 2: Factors considered in setting ASPs

The methodology for setting ASPs draws on the Department's latest view on generation costs to produce a modelled 'supply curve' for each technology in each delivery year. For certain factors, the Department has adjusted or updated assumptions from the 2023 Electricity Generation Costs Report[3], to reflect the fast-moving conditions in the industry and ensure ASPs are fit for purpose in protecting consumers whilst encouraging auction participation. Where this is the case, it is detailed in Section 4: Assumptions.

The supply curve represents the estimated volume of capacity in MW that could be built at different strike prices, ranked from cheapest to most expensive. This is represented graphically as an upward-sloping curve, with more projects expected to be financially viable as the ASP is increased, as illustrated in Figure 1.

Figure 1. Illustrative Supply Curve



The ASP that is estimated to incentivise a certain capacity of deployment is determined through a discounted cash-flow calculation for each project in the supply curve. The 'marginal project' is then identified as the most expensive project within the targeted deployment range (the cheapest 25% or 75% of the supply curve). The ASP is determined as the price that sets the net present value of this project's cash-flows equal to zero, taking account of the revenues in the wholesale market and from other relevant sources (such as the sale of heat produced by projects deploying with Combined Heat and Power) throughout the project lifetime and after the end of the CfD. The project cash-flows are discounted at the Department's view of technology hurdle rates. Real, not nominal, hurdle rates are applied, and the calculation is based in a consistent real price base, meaning that any difference between inflationary expectations and outturn Consumer Price Index (CPI) inflation that developers experience throughout the contract lifetime is not accounted for.

[3] https://www.gov.uk/government/publications/electricity-generation-costs-2023. This link also applies to further references to the 2023 Electricity Generation Costs Report.

For AR6, as with Allocation Round 5 (AR5), the calculated ASPs for each delivery year relevant to that technology have been compared, and a single ASP has been taken based on the maximum across the relevant years. This simplifies the allocation process and aligns with the use of a single clearing price, whilst reducing the risk that an individual project is unable to participate in the auction.

In light of the objectives set out in Section 1, in setting ASPs the Department has considered a range of factors, including:

- **Technology specific factors** such as capital and operating costs, financing costs as well as any build constraints.
- **Market conditions** such as estimated wholesale electricity prices and the discount which generators may face when signing a Power Purchase Agreement (PPA).
- **Policy considerations** such as the statutory purpose of the scheme to encourage low carbon electricity generation and the need to have regard to meet Carbon Budget 6 (CB6) and Net Zero targets, the likely cost to consumers, and ensuring security of supply. In addition, we can consider other factors including driving technology cost reductions and deployment scalability. ASPs have also been set to encourage a significant proportion of potential projects to come forward and compete in the allocation round – for this allocation round, this level has been set at 25% of the modelled supply curve for each technology, with Offshore Wind, Floating Offshore wind, Onshore Wind, Solar PV and Remote Island Wind set at 75% of the modelled supply curve.

Section 3: Approach to setting ASPs

3.1 Approach Overview

Figure 2 provides a high-level summary of the approach used to set ASPs. Further detail is provided in Section 3.2.

Figure 2: Approach overview

1. Gather data to estimate lifetime cash-flows
2. Sum the net present value of total expected costs and revenues in each year
3. Set the strike price to make the NPV equal to zero
4. Repeat for a range of project costs to create a supply curve
5. Identify the percentage of pipeline capacity to bring forward per technology and set ASPs at the corresponding strike price

3.2 Step-by-step approach

Step 1: Gather data to estimate lifetime cash-flows

Table 2 outlines the key data inputs for estimating project lifetime cash-flows. The primary sources used for these inputs are the Department's latest view on generation costs and market price projections. Further details on data sources can be found in Section 4.

Table 2: Key data and assumptions

Capex costs	Opex costs and revenues	Decommissioning costs	Generation and other key data
Pre-development costs	Fixed opex	Financial security costs	Capacity of plant
Construction costs	Variable opex	Cost of decommissioning	Availability
Infrastructure costs	Insurance		Efficiency
	Connection costs		Load factor
	Heat revenues		Hurdle rate
	Fuel costs/gate fees		
	Strike price revenue (determined in Step 3)		

Costs and revenues relevant to the project, but partly determined by the developer's wider operations, such as changes to the corporate tax regime, are not accounted for. This would require detailed financial assumptions beyond the project costs and revenues and would vary significantly across projects. Therefore, any analysis of corporate tax would likely not be representative of a ‘typical project’ that the supply curve models. The hurdle rates applied to discount cash-flows are pre-tax, consistent with this approach.

Step 2: Sum the net present value of total expected costs and revenues in each year

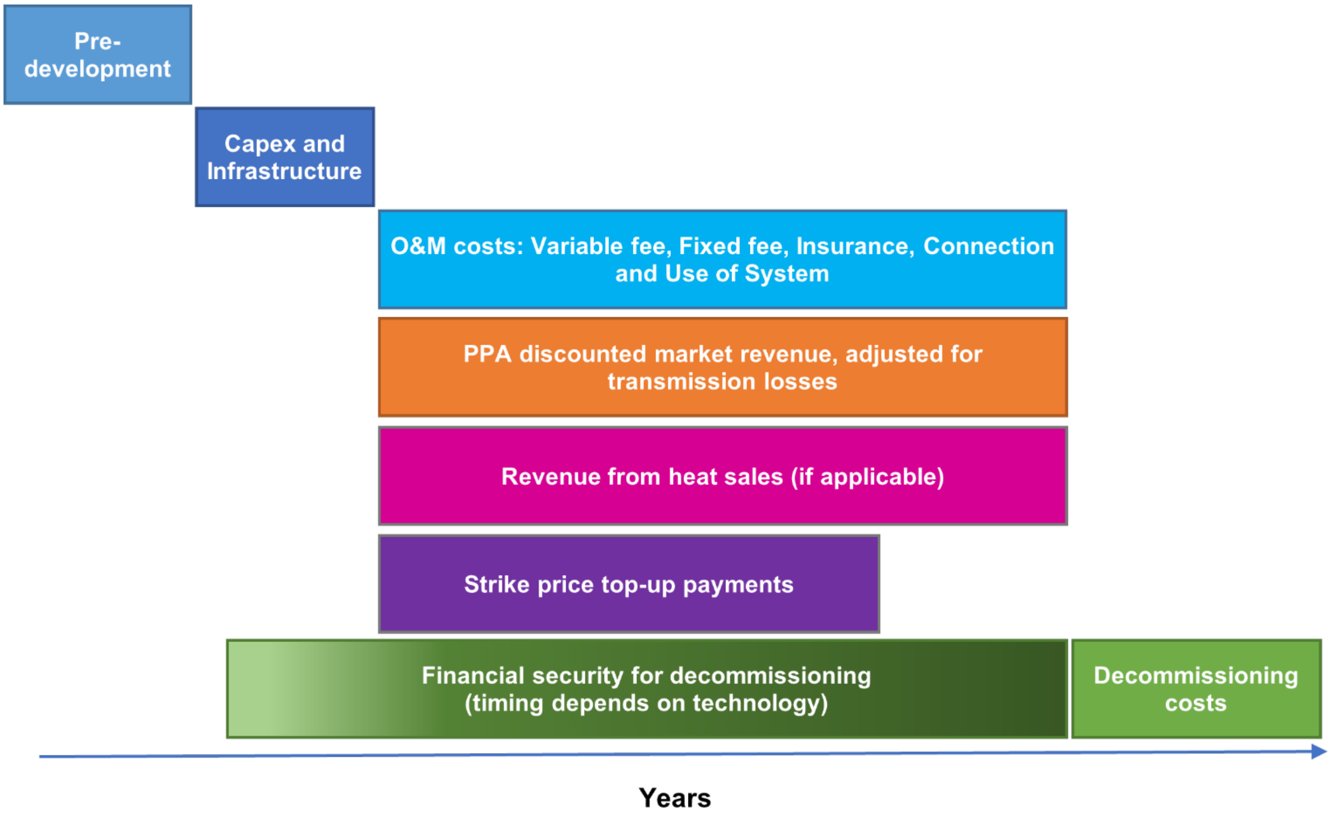
Costs and revenues are summed in each year over the lifetime of the project, and discounted by the hurdle rate for the technology (which accounts for relevant financing costs) to give the net present value (NPV) of lifetime cash-flows:

$$\mathrm{NPV} = \sum_{\mathrm{n}} \frac{\text{Total capex, opex, decommissioning costs and revenues}_{\mathrm{n}}}{(1 + \text{discount rate})^{\mathrm{n}}}$$

$$\mathrm{n} = \text{years}$$

Figure 3 illustrates how the timings of these costs and revenues are accounted for in the calculation.

Figure 3: Illustrative timings of project costs and revenues



Step 3: Set the strike price to make the NPV equal to zero

The strike price is set at the level at which the NPV of the project's lifetime costs and revenues is equal to zero. The strike price therefore represents the level of total revenue under the CfD required for the relevant project to achieve a rate of return equal to the Department's view of technology hurdle rates.

Step 4: Repeat for a range of project costs to create the supply curve

In previous rounds, for Offshore Wind and Remote Island Wind, the supply curve was constructed based on individual projects in the known pipeline, based on a combination of bespoke and generic cost and generation assumptions. However, the Department is no longer using this approach for AR6, and for all technologies, the supply curve is created using a generic approach by varying capex costs. This approach has the benefit of ASPs being less influenced by the marginal project in the supply curve, and therefore the ASP is less to fluctuate between rounds. As part of the change for Remote Island Wind, we have aligned our methodology and assumptions for this technology with Onshore Wind. Therefore, any references to Onshore Wind below also apply to Remote Island Wind.

To create the supply curve by technology, the range of viable strike prices has been estimated by assuming that pre-development, construction, and infrastructure costs increase linearly from the first project to the last project in the supply curve, where the low point on the supply curve assumes that low pre-development, construction, and infrastructure cost apply to this particular project. Operating costs and all other cost and non-strike price revenue assumptions (for example load factors, hurdle rates and fuel costs where applicable) are assumed to be constant across the length of the supply curve.[4]

Technologies that are grouped together in a single category under the CfD are combined into a single supply curve based on the estimated total pipeline capacity across the variants that would be viable at each strike price.

Step 5: Identify the percentage of pipeline capacity that would enable a high level of participation and set ASPs at the corresponding strike price

A point on the supply curve is chosen to encourage participation in the auction, ensure competition and fulfil policy objectives.

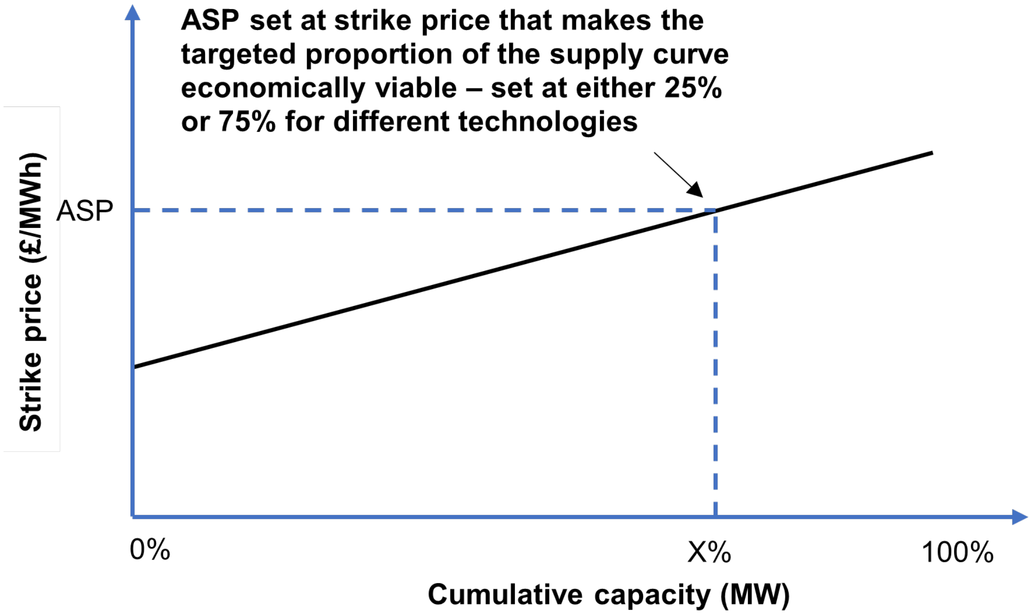
For this allocation round, as explained further in section 4.2, recognising our high decarbonisation ambitions, the targeted proportion of the supply curve for technologies key to our decarbonisation pathways (Offshore Wind, Onshore Wind, Remote Island Wind, Floating Offshore Wind and Solar PV), is set at 75%, i.e. the ASP for each technology and delivery year corresponds to the strike price that is estimated to make 75% of pipeline projects economically viable, as illustrated in Figure 4.

For emerging technologies, where industries are still developing and costs to consumers are potentially high, and for other baseload renewables where there is not a clear deployment trajectory needed to meet our decarbonisation targets, the targeted proportion remains at 25% of the supply curve.

[4] The variation in overall levelised costs across these supply curves, due to the assumed variation in capital costs, is intended to proxy the variation in overall levelised costs across the potential new projects, which itself will reflect variations across all cost components.

In line with the methodology used in AR5, the calculated ASPs for each delivery year relevant to that technology are compared, and a single ASP is then taken based on the maximum across the relevant years. The ASP is then rounded to the nearest £1/MWh.

Figure 4. Setting the Administrative Strike Price



Section 4: Assumptions

The key data source used in setting ASPs is Department's latest view on electricity generation costs, which builds on the evidence base from the 2023 Electricity Generation Costs Report. This includes assumptions on pre-development costs, construction costs, operating and maintenance costs, connection and use of system charges, load factors and efficiencies, and project timings.

We are in an unprecedented period where fast moving economic and market conditions mean that, for some technologies, our most recent 2023 Electricity Generation Costs Report does not reflect the current market expectations. Where this is the case, we have outlined the approach used in detail below. This is to ensure that our assumptions meet the objectives of setting ASPs set out above. Further, where additional assumptions are used beyond what is included in generation costs, such as revenue assumptions, these are explained below.

4.1 Cross-cutting assumptions

Capital expenditure costs (capex)

Analysis completed in recent months confirms that the current macroeconomic environment has placed unprecedented upwards pressure on renewable project costs. There is clear evidence of input costs rising faster than general price inflation, increasing capital expenditure (capex) costs (construction costs and infrastructure costs) in particular. In addition, interest rate rises have increased financing costs. ASPs play an important role in protecting consumers, but the evidence underpinning them should reflect a sustainable price level at which renewable projects can deliver. Bespoke adjustments have therefore been applied to the Electricity Generation Costs Report 2023 capex assumptions to reflect the recent rise in input costs and live project circumstances.

Adjustments to capex assumptions for Offshore Wind, Onshore Wind (including Remote Island Wind) and Solar PV

The Department has worked extensively with Baringa to develop a methodology to understand the input cost changes that renewables projects experienced over the three years preceding 2023. This research focussed on technologies which are key to our decarbonisation pathways (Offshore Wind, Onshore Wind (including Remote Island Wind) and Solar PV, see Energy and emissions projections: Net Zero Strategy baseline Annex O[5]). The analysis suggested that based on the observed changes in input costs, renewable project costs have increased at a rate that exceeded CPI inflation. In the context of a fast-moving macroeconomic environment, the Department has further updated this analysis for subsequent changes in commodity prices and market conditions.

The approach for Offshore Wind, Onshore Wind, and Solar PV consisted of breaking down capex spend into individual component parts, such as 'turbines' for Offshore and Onshore wind or 'modules' for Solar, which were then broken down into individual commodities such as steel, iron, copper etc. It was not possible to track all parts of capex spend to individual commodities,

[5] https://www.gov.uk/government/publications/energy-and-emissions-projections-2021-to-2040

so for the proportion of trend that was not tracked, the Department has inflated costs by the Input Producer Price Index (PPI). PPI is likely to be a more accurate representation of commodity price changes in a period where PPI has exceeded CPI, and although it is possible that not all capex spend has risen in line with PPI, the Department judges that using this assumption better reflects significant underlying cost uncertainty at present, as well as the intention of ASPs acting as an auction backstop rather than a significant constraint on participation.

The difference between capex in 2020 and 2023 was then assessed based on the commodity price data and PPI. 2020 is used as a benchmark year as it provides a stable baseline value for commodity prices before the recent period of commodity price inflation. The Department considered the nominal inflation between 2020 and 2023 and took the difference between this inflation rate and the Consumer Price Index (CPI), to which CfD contracts are indexed. This capex uplift was then applied to the construction and infrastructure cost estimates from the 2023 Electricity Generation Costs Report. No adjustment is made to pre-development costs.

The Department recognises that there have been developments in the supply chain over the last year beyond raw commodity price increases. It is not possible to account for these changes in supply chain dynamics explicitly as they reflect the outcome of individual commercial negotiations between developers and suppliers, which vary significantly by project and which the Department is not privy to the detail of. However, we judge that the combination of less conservative assumptions here and elsewhere in our methodological adjustments are sufficient to account for a broad degree of uncertainty.

Adjustments to capex assumptions for other technologies

The previously described commodity price approach focussed on technologies key to our decarbonisation pathways (Offshore Wind, Onshore Wind (including Remote Island Wind), Solar PV). For Floating Offshore Wind and Tidal Stream, no additional uplift is required to the Department’s capex assumptions given that new research was completed in 2023 and therefore costs are reflective of a 2023 cost base. The outputs of this research have been summarised in the 2023 Electricity Generation Costs Report. For all other technologies, capex costs are uplifted by the difference between PPI and CPI over 2020-2023. As per Offshore Wind, Onshore Wind and Solar PV, this adjustment is applied to the construction cost and infrastructure cost elements of total capex and is not applied to pre-development costs.

The percentage uplift to construction costs, and the construction and infrastructure costs for each technology are presented below in Table 3. Note that the Department’s ASP calculation is in real terms, so the uplift presented below is above CPI inflation, to which CfD contracts are indexed. The figures align with costs for the delivery year and the targeted proportion of the supply curve which sets the ASP for each technology. As explained in section 3, the low, central and high point of our supply curve use the low, central and high capex and infrastructure assumptions respectively. Due to this and the delivery year used, these figures are not directly comparable to specific figures in the published 2023 Electricity Generation Costs Report.

Table 3: Construction and Infrastructure Cost Assumptions (2021 prices)[6]

Technology Type	Real terms uplift to construction costs[7]	Construction costs used in ASPs (£/KW)	Infrastructure Costs used in ASPs (£'000)
ACT	13%	5700	1600
Anaerobic Digestion (>5MW)	13%	4300	800
Dedicated Biomass with CHP	13%	5600	1000
Energy from Waste with CHP	13%	12600	5800
Floating Offshore Wind	0%	5200	0
Geothermal	13%	6200	300
Hydro (>5MW and <50MW)	13%	2900	0
Landfill Gas	13%	2000	800
Offshore Wind	26%	2000	87600
Onshore Wind (>5MW)	24%	1400	5300
Remote Island Wind (>5MW)	24%	1400	5300
Sewage Gas	13%	4500	200
Solar PV (>5MW)	20%	400	1800
Tidal Stream[8]	0%	5100	0
Wave	13%	4200	5200

Hurdle rates

Hurdle rates are sourced from a commissioned report from Europe Economics (EE)[9], updating the Department's financing cost assumptions for projects starting development from 2018 in a range of technologies. The Department is aware that interest rate increases since have led to increases in the cost of debt (a component of hurdle rates) faced by project developers. However, having undertaken benchmarking against market commentator assumptions for selected technologies, counteracting movements in the cost of equity and debt mean the Department deems that, overall, the current EE hurdle rate assumptions remain sufficiently high. As a result, in general, no revision of hurdle rates is needed for AR6. A separate risk

[6] For technologies with CHP and non-CHP variants we show the assumptions for the variant used for the ASP, as explained in section 4.2

[7] No adjustment is applied to Floating Offshore Wind and Tidal Stream as the latest Generation Cost research, carried out by Frazer-Nash consultancy, is reflective of 2023 costs.

[8] The capex figures shown are the low-cost assumption of medium-FOAK assumptions from the 2023 Generation Cost Report. As detailed in section 4.2, the Tidal Stream ASP is set reflecting evidence of the AR5 clearing price, as well as generation cost data. For this reason, the figures shown will be above the implicit costs reflected in the Tidal ASP

[9] Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies: https://www.gov.uk/government/publications/cost-of-capital-update-for-electricity-generation-storage-and-dsr-technologies

premium, specific to AR6, and over and above the hurdle rate, has been implemented to reflect live uncertainties for specific technologies, and is discussed later in this document. The Department will keep these assumptions under review for future rounds given the recent changes to the macroeconomic environment.

Table 4 shows current hurdle rate assumptions in real terms (pre-tax), including a 2% risk premium on Offshore Wind and Floating Offshore Wind, and a 1% risk premium on Onshore Wind and Remote Island Wind.

Table 4: Hurdle Rate Assumptions[10]

Technology Type	Hurdle Rate
ACT	8.10%
Anaerobic Digestion (>5MW)	8.30%
Dedicated Biomass with CHP	9.90%
Energy from Waste with CHP	7.60%
Floating Offshore Wind	9.80%
Geothermal	18.80%
Hydro (>5MW and <50MW)	5.40%
Landfill Gas	6.10%
Offshore Wind	8.30%
Onshore Wind (>5MW)	6.20%
Remote Island Wind (>5MW)	6.20%
Sewage Gas	7.10%
Solar PV (>5MW)	5.00%
Tidal Stream	9.40%
Wave	8.60%

Hurdle rate for Floating Offshore Wind

The hurdle rate for Floating Offshore Wind was not published in the EE report as it was not considered separately to Offshore Wind. The Department uses 7.8%, as with previous rounds, as the hurdle rate before the risk premium is applied. This was determined by estimating a range for Floating Offshore Wind hurdle rates using three methods, with the EE report as a baseline for consistency. The three approaches are set out below and were weighted equally to determine the point estimate.

Firstly, a premium was added to the fixed Offshore Wind hurdle rate from the EE report. This took the form of reversing an assumed decrease in asset beta[11] leading up to the 2018 report.

[10] For technologies with CHP and non-CHP variants we show the hurdle rate for the variant used for the ASP, as explained in section 4.2

[11] Asset beta measures market risk, considering the volatility of returns excluding the impact of debt.

Secondly, the closest comparator technologies with published hurdle rates were considered as proxies for the Floating Offshore Wind hurdle rate. Comparator technologies were determined by examining risk profiles, technology readiness level, and whether generation is intermittent. Wave power was determined to be the closest comparator. Lastly, third party sources were examined to determine the delta between fixed and Floating Offshore Wind. Weighting these methods equally implies a delta of c.150bps over fixed Offshore Wind, leading to a 7.8% hurdle rate for Floating Offshore Wind before applying a risk premium. This approach gives the Department some assurance of the likely hurdle rate.

Load factors

The load factors used for ASPs align with the figures and approach detailed in the published 2023 Electricity Generation Costs Report for each technology. The load factors published in the Allocation Framework for use in the budget valuation follow a similar approach, but for that purpose, as detailed in the 2018 CfD consultation on 'proposed amendments to the scheme'[12] we use higher load factors to mitigate the risk that in-life spend is higher than estimated in the auction.

Gross load factors for the wind technologies are calculated using an internal departmental model, which combines a theoretical turbine power curve (power output as a function of wind speed, modelled using turbine technology parameters including rotor swept area and hub height) with historic site-specific Virtual Met Mast (VMM) hourly wind speed data sourced from the UK Met Office.

The VMM accounts for local complexity such as the effects of local topography and near-coast effect and covers a period of over 34 years. This means the gross load factor calculated considers both windy and non-windy years, so will be different to actual gross load factor for a specific year. Load factors increase with turbine size as larger turbines have longer blades that are able to capture more energy from the available wind and access higher wind speeds due their increased height. To convert from gross to net load factors an assumption is used to account for the availability of the wind farm. To produce the load factor used in ASP modelling we take a broad view across potential locations of future capacity and cannot reflect site specifics of individual projects.

The Department understands that developers of wind technologies may factor in curtailment into their net load factors when estimating project revenues. The Department applies economic curtailment assumptions separately to the net load factor when calculating ASPs, meaning that net load factors used in the Department's modelling and developers' assumptions can vary, as well as due to site specific factors. Economic curtailment estimates from the from the Department's in-house power sector model – the Dynamic Dispatch Model (DDM)[13] are used, (which are consistent with a Net Zero power system generation mix (see Energy and emissions projections: Net Zero Strategy baseline Annex O[14]). As an indication of the impact of this, the curtailment assumptions applied when calculating ASPs reduces the Offshore Wind load factor shown in Table 5 during the CfD period by around 5 percentage points.

[12] https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme
[13] Dynamic Dispatch Model: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/65709/5425-decc-dynamic-dispatch-model-ddm.pdf
[14] https://www.gov.uk/government/publications/energy-and-emissions-projections-2021-to-2040

Table 5: Net Load Factor Assumptions[15]

Technology Type	Net Load Factor
ACT	71%
Anaerobic Digestion (>5MW)	79%
Dedicated Biomass with CHP	80%
Energy from Waste with CHP	81%
Floating Offshore Wind	56%
Geothermal	90%
Hydro (>5MW and <50MW)	35%
Landfill Gas	58%
Offshore Wind	62%
Onshore Wind (>5MW)	45%
Remote Island Wind (>5MW)	45%
Sewage Gas	46%
Solar PV (>5MW)	11%
Tidal Stream[16]	37%
Wave	30%

Operating Costs

As detailed in section 3, operating costs are assumed to be constant across the supply curve. For most technologies, these assumptions will align with the central assumptions from the 2023 Electricity Generation Cost Report. For Onshore Wind, Offshore Wind and Floating Offshore Wind we have taken a different approach for Connection and Use of System Charges assumptions, as detailed below.

Connection and Use of System (UoS) Charges

For most technologies the Connection and UoS charges are sourced from the 2023 Electricity Generation Costs Report.

For Onshore Wind and Offshore Wind, connection and UoS charges are estimated using an internal departmental model which uses published information including the latest National Grid ESO 2023 five-year Transmission Network Use of System (TNUoS) forecast[17] and the

[15] These are the net load factors which underpin the ASP which is the maximum across the delivery years, as explained in section 2. For technologies with CHP and non-CHP variants we show the load factor for the variant used for the CHP, as explained in section 4.2

[16] The load factor figure shown for Tidal Stream is the load factor for medium-FOAK assumptions from the 2023 Generation Costs Report. This is reflective of the assumptions used in the supply curve at the level the ASP is set. Further detail of the Tidal Stream approach is in section 4.2.

[17] https://www.nationalgrideso.com/document/279606/download

Department's Digest of UK Energy Statistics (DUKES) publication[18]. We use the local TNUoS charge estimates from the National Grid forecast for existing projects and estimate the wider locational TNUoS charges using the National Grid forecast for 2028/29 and project locations from DUKES. We use this information to calculate a representative figure for each technology.

As stated in Section 3, operating costs are assumed to be constant throughout our supply curve and an assumed central estimate is taken. However, we acknowledge that for Onshore Wind, Offshore Wind and Floating Offshore Wind, network charges are a key driver of cost, with significant variation across projects. For this allocation round, we have used a higher connection charge estimate to be reflective of the higher proportion of the supply curve we are targeting (75%) for these technologies. For these technologies this is representative of a transmission connected project in a more expensive connection zone. These figures are shown in Table 6.

For Floating Offshore Wind, as covered in Section 4.2 our cost assumptions align with the published 2023 Electricity Generation Costs Report assumptions, which is based on the published research completed for the Department by Frazer-Nash consultancy[19]. These assumptions group connection and UoS charges into an overall fixed operating and maintenance (O&M) cost assumption. We have therefore calculated an adjusted fixed O&M cost assumption, reflective of a higher TNUoS charge, informed by the difference in wider TNUoS charges across different TNUoS zones, and potential future project locations. This figure is shown in Table 7.

National Grid ESO have recently published a 10-year projection of TNUoS costs. Although subject to significant uncertainty, and distinct from the 5-year forecast taken as the baseline in our ASP assumptions, this projection highlights uncertainty faced by renewable project developers, particularly for technologies where a significant proportion of capacity is transmission-connected. This uncertainty has been accounted for separately and is discussed in section 4.2 below.

Table 6 Offshore Wind and Onshore Wind Connection and UoS Charges (2021 prices)[20]

Technology Type	Connection and UoS Charges (£/MW/Year)
Offshore Wind	69700
Onshore Wind	22400

[18] https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
[19] https://www.gov.uk/government/publications/review-of-power-generation-costs-for-floating-offshore-wind-and-tidal-stream-energy-technologies
[20] The figures shown are the connection and UoS charge costs used to set the ASP. These are not directly comparable to published Generation Cost Assumptions where assumed opex reductions over time are included in the figures presented.

Table 7: Floating Offshore Wind Fixed O&M Cost Assumption (2021 prices)

Technology	Fixed O&M Costs (£/MW/Year)
Floating Offshore Wind	124700

Revenues

For power revenues, market price assumptions (including estimates of wholesale prices and PPA discount factor assumptions) have been sourced from the DDM. Different market prices are assumed to be captured by baseload technologies (such as ACT) compared to intermittent technologies (such as Offshore Wind).

For baseload technologies this uses the modelled season ahead price (average wholesale). For intermittent technologies, day ahead hourly prices are estimated based on intra-day half-hourly prices. An individual wholesale reference price series is estimated for Wind technologies (applicable to Offshore Wind, Onshore Wind, and Floating Offshore Wind), Solar PV and Hydro. These prices reflect the estimated average price which each technology could achieve in the market based on when they are expected to generate. For technologies other than those listed above, a suitable proxy capture price is used. Schedule 2 Appendix 2 of the final Allocation Framework published alongside the Budget Notice will set out the reference price series used in the valuation formula, with Schedule 3 setting out which technologies each series is applied to[21]. The same series are applied to the same technologies for the purposes of informing ASPs, albeit estimated over a longer period. Further detail on the interaction between reference prices and parameters will be published alongside the Budget Notice.

Heat revenues are calculated based on the avoided retail cost of gas needed to be purchased. This approach estimates the cost that would have been incurred by the heat off-taker (the buyer of the heat produced by the CHP plant) if they were to produce the same amount of heat using a boiler. This would incur fuel costs at the retail gas price, which are avoided by buying heat from the CHP plant. Geothermal is assumed to have 40% heat demand (the proportion of time when generated heat would be sold) given the geographical location restrictions and seasonal considerations for this technology. This assumption is based on responses to the 2016 Call for Evidence on Fuelled and Geothermal Technologies in the CfD Scheme.[22] For all other technologies deploying with CHP heat demand is assumed to be 100% in line with 2023 Electricity Generation Costs Report.

Decommissioning costs and scrappage value

For Offshore Wind, decommissioning costs have been estimated using the Department's decommissioning cost model[23] (developed by ARUP). For other technologies, decommissioning cost assumptions have been informed by information included in planning applications, decommissioning plans submitted to the Department, independent cost

[21] These reference prices are used for the purposes of informing ASPs, and in the valuation formula to estimate monetary budget during the allocation round. They do not influence or predicate the reference prices used by the Low Carbon Contracts Company (LCCC) to calculate payments in-life.
[22] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme
[23] Cost estimation and liabilities in decommissioning offshore wind installations: https://www.gov.uk/government/publications/decommissioning-offshore-wind-installations-cost-estimation

assessments of decommissioning plans (commissioned by the Department) and internal departmental expertise.

For all technologies it is also assumed that developers must provide a financial security during the lifetime of the project to cover the costs of decommissioning at end of project life. Internal commercial expertise has been used to inform estimates of the cost of these financial securities. Timings of financial securities have been informed from the Department's decommissioning guidance and internal expertise.

Scrappage value assumptions have been informed by decommissioning plans submitted to the Department, independent cost assessments of decommissioning plans (commissioned by the Department) and internal expertise.

Comparison of ASPs and the Levelised Cost of Electricity (LCOEs, levelised costs)

The 2023 Electricity Generation Costs Report provides many of the underlying assumptions for ASPs. It includes LCOEs for some of the technologies eligible to participate in the CfD, however it is important to note that an ASP for a particular technology is different to the LCOE – the average cost over the lifetime of the plant per MWh generated. Relative to this LCOE, an equivalent strike price could be higher or lower for several different reasons, all of which are taken into account in the setting of these ASPs:

Costs not included in The Department's standard LCOEs:

- **CfD payments**: CfD top-up payments will be paid based on generation after taking account of the generator's share of transmission losses, known as the Transmission Loss Multiplier, so the ASPs need to be increased to account for this.

- **PPAs:** The revenue received by the generator is a combination of the estimated wholesale market price and the CfD top-up, which is the difference between the strike price and the reference price. Where the generator is assumed to not be able to achieve the reference price because it sells its power through a PPA at a discount to the market price (or faces equivalent transaction costs within a vertically-integrated utility), the ASP must be increased to compensate for this. PPA discounts therefore reflect route to market costs including the costs of trading and imbalance costs.

- **Contract length:** The levelised cost is defined over the operating life of a project. Assuming the CfD contract length of 15 years is shorter than the operating life, and wholesale market revenues and any relevant heat sale revenues (for CHP plants) post-contract are lower than the levelised cost then, all other things being equal, the ASP must be increased above the levelised cost to compensate for this. Therefore, the ASP calculation factors in the remainder of project life revenues post-CfD expiry.

- **Other relevant information specific to setting ASPs:** This includes policy considerations such as CfD eligibility criteria for each technology, technology-specific estimates for decommissioning costs and scrappage values not included in the Department's definition of levelised costs, and other relevant evidence of developments within industry.

Further, ASPs are set to bring forward the most cost-effective projects, which may not be the same as the estimates of typical project costs. For all these reasons, the ASPs presented here may be significantly different from the levelised costs for each technology.

4.2 Technology-specific approaches

The following technology-specific approaches have been applied to reflect the best evidence available when estimating project costs and technology supply curves.

Risk premium for Offshore Wind, Floating Offshore Wind and Onshore Wind (including Remote Island Wind)

Renewable projects are facing an unprecedented level of uncertainty in the current, fast-moving investment climate. This reflects a variety of factors which impact technologies differently. In this context, the Department has introduced a risk premium for selected (wind) technologies, applied as an addition to the hurdle rate, as an exceptional adjustment for AR6. The premiums and factors considered when setting them are outlined below and may not apply to future rounds.

National Grid ESO recently published a 10-year projection for TNUoS charges. Ofgem state that these projections will continue to evolve and do not necessarily reflect amounts that customers and generators will pay due to potential TNUoS reforms and changes to National Grid charging methodology, highlighting the uncertainty faced by developers in pricing in future TNUoS charges. This projection will impact technologies with more transmission-connected projects in more expensive TNUoS zones. In practice, this means it primarily impacts wind technologies.

There are further uncertainties specific to Offshore Wind and Floating Offshore Wind. Their supply chains are complex, rendering it difficult to determine cost changes with a high degree of certainty. They have faced specific and well publicised challenges that cannot solely be traced back to changes in individual commodity prices, and have impacted them more significantly than other technologies, demonstrated by difficulties taking investment decisions in the UK and abroad. This uncertainty is compounded by variability across projects, with developments impacting developers differently based on the outcome of individual negotiations with key suppliers. The lack of capacity and limited price discovery secured for these technologies in AR5 further increases uncertainty on project costs.

The Department judges that the combination of cost uncertainty, complex supply chains, lack of capacity and limited price discovery secured through AR5, and TNUoS uncertainty is specific to Fixed and Floating Offshore Wind. Onshore wind is also at risk from high TNUoS charges.

The hurdle rate risk premium will apply in addition to the increase in supply curve targets to 75% for selected technologies. It will allow room for future price movements until project costs are secured. This will support the ambition for the ASP to act as a backstop for the auction rather than a significant constraint on participation.

A risk premium of 2% is added to the hurdle rates of Fixed and Floating Offshore Wind to reflect the uncertainty of longer term TNUoS charges and wider cost uncertainties. A risk premium of 1% is added to the hurdle rate of Onshore Wind to reflect only the uncertainty of longer term TNUoS charges.

Table 8: Hurdle Rates with and without Risk Premium Assumptions

Technology Type	Baseline Hurdle Rate	Hurdle Rate with Risk Premium
Floating Offshore Wind	7.80%	9.80%
Offshore Wind	6.30%	8.30%
Onshore Wind	5.20%	6.20%

The Department explored several market data reference points to establish a suitable risk premium. The delta between subsidised and merchant project hurdle rates for Offshore Wind was also considered in order to distinguish this additional risk uncertainty with the risk for unsubsidised projects. Developers are expected to pursue internal risk management practices, allowing the risk premium to capture some but not all the uncertainty.

Tidal Stream generation costs

The evidence base used for Tidal Stream aligns with the published 2023 Electricity Generation Costs Report assumptions, based on the published research completed for the Department in 2023 by Frazer-Nash consultancy[24]. In these publications, the cost and technical assumptions and LCOE estimates are presented for different categories of Tidal Stream. This represents projects with different sizes and at different development stages, covering Demo, First Of A Kind (FOAK) and Nth Of A Kind (NOAK). Given the range of different types of projects within these categories, Frazer Nash provided data for small, medium and large variations.

For the purposes of ASP modelling, in our modelled supply curve we have used the assumptions for medium Demo and medium FOAK projects as these are most representative of the potential pipeline of projects which could participate in AR6. Frazer Nash determined these to be projects which have a total capacity of between 8 – 20 MW, with 4 - 10 turbines with capacity of 2MW. It is plausible that projects which participate in AR6 do not fit these categories, but we have judged these to cover the majority of projects. These categories, medium Demo and medium FOAK, are used to determine different points on our modelled supply curve, representing the different potential strike prices at which Tidal Stream projects could deliver.

The research also provided costs in both a 2020 cost base and 2023 cost base, reflecting increased input costs over those three years. In line with our approach for other technologies for AR6, which have seen capex adjustments based on rising input costs from 2020 to 2023, the 2023 cost base is used to determine the Tidal Stream ASP. It is possible that not all projects participating in AR6 will have seen cost rises equivalent to the magnitude estimated in the research, for example if they were able to lock-in prices with the supply chain earlier in project development. However, using the 2023 cost base ensures that the current macroeconomic environment is reflected in the ASP.

In addition to generation costs data, we have also used evidence from AR5 where Tidal Stream projects were successful at a price of £198/MWh (2012 prices). This is below the ASP

[24] https://www.gov.uk/government/publications/review-of-power-generation-costs-for-floating-offshore-wind-and-tidal-stream-energy-technologies

level that would be implied by using the medium Demo or medium FOAK data in the supply curve. Although AR5 is evidence of the price projects could deliver at, there is a risk to relying solely on this information to inform our ASP when independent evidence from the research suggests costs could be higher.

Given underlying uncertainty, the AR5 clearing price is used alongside the generation cost data to estimate the supply curve for the AR6 Tidal Stream ASP. The lowest point on the supply curve is set at the AR5 clearing price £198/MWh (2012 price). The lower 50% of the supply curve is then based on strike prices derived by varying medium FOAK project costs. The upper 50% is based on strike prices derived by varying medium DEMO project costs. The overall supply curve is therefore representative of the price recently discovered through competition allocation, and the range of costs that could reflect both Demo and FOAK projects deploying in AR6.

Floating Offshore Wind generation costs

The evidence base used for Floating Offshore Wind aligns with the published 2023 Electricity Generation Costs Report assumptions, based on the published research completed for the Department in 2023 by Frazer-Nash consultancy[25]. In these publications, the cost and technical assumptions and LCOEs are presented for different categories of Floating Offshore Wind. This represents projects with different sizes and at different development stages, covering Demo, First Of A Kind (FOAK) and Nth Of A Kind (NOAK).

For the purposes of ASP modelling in AR6 we have used the assumptions associated with Demo projects. Frazer Nash classify this as projects which are relatively close to shore, have a capacity of less than around 200MW, and are planned to achieve first power before 2030. This is deemed to be representative of the projects which we expect to participate in AR6. As shown in the Generation Costs Report, Demo projects are expected to have higher underlying cost assumptions and LCOEs than FOAK and NOAK projects.

As explained in section 4.1, no additional uplift has been applied to the capex costs for Floating Offshore Wind given the research was completed in 2023 and is therefore reflective of a 2023 cost base.

In line with the approach detailed in the Generation Costs Report, we have adjusted the load factor assumptions from those provided by the Frazer Nash research. For this we have used the same approach as detailed above in section 4.1 for other wind technologies. Load factors increase with turbine size and we have assumed a 12MW turbine size for AR6 projects. This is based on an assessment of turbine sizes of existing and potential future projects. This is lower than the assumed size of fixed bottom projects and is more representative of the nascent nature of the industry. It is plausible AR6 projects use different turbine sizes than we have assumed given the differing characteristics of these projects.

Offshore Wind and Remote Island Wind

In previous allocation rounds we constructed supply curves for Offshore Wind and Remote Island Wind consisting of specific known projects in the pipeline. For AR6 we have changed the approach for these technologies to align with the approach for all other technologies, detailed in section 3 above. This change of approach for Offshore Wind and Remote Island

[25] https://www.gov.uk/government/publications/review-of-power-generation-costs-for-floating-offshore-wind-and-tidal-stream-energy-technologies

Wind has the benefit of ASPs being less influenced by the marginal project in the supply curve, and therefore the ASP is less likely to fluctuate between rounds. As part of the change for Remote Island Wind, we have aligned our methodology and assumptions for this technology with Onshore Wind. Evidence from previous allocation rounds suggests that Remote Island Wind can deliver at a comparable strike price to that of Onshore Wind.

Anaerobic Digestion (AD), Geothermal and Advanced Conversion Technologies (ACT)

AD, ACT and Geothermal technologies have the option to deploy with or without CHP, and these two variants have different generation costs associated with them. These variants have been combined based on an assumed breakdown of pipeline projects informed by information in the Renewable Energy Planning Database (REPD)[26], published information on projects, and internal expertise. Based on these sources, we assume that all Geothermal projects will deploy with CHP and so the generation cost estimates for this variant have been used. For AD and ACT, we assume that all projects will deploy without CHP and so only 'without CHP' generation cost estimates have been applied.

Targeted proportion of the supply curve for Offshore Wind, Floating Offshore Wind, Onshore Wind, Remote Island Wind and Solar PV

For Offshore Wind, Floating Offshore Wind, Onshore Wind, Remote Island Wind and Solar PV, a greater proportion of the supply curve is targeted than other technologies (75%, versus 25% for others). This is an increase compared with AR5 for Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV, which were all 50% in AR5, and Remote Island Wind which was 25% in AR5.

This approach better reflects Government's decarbonisation objectives to meet Carbon Budget 6 and Net Zero, and is line with the public statements included in The British Energy Security Strategy[27] (BESS) and the Net Zero Strategy[28] (NZS).

Meeting these commitments requires deploying significant quantities of Offshore Wind, Floating Offshore Wind, Onshore Wind (including Remote Island Wind) and Solar PV capacity, as shown in Energy and emissions projections: Net Zero Strategy baseline Annex O[29], and the change is designed to enable greatest participation whilst seeking to retain sufficient levels of competitive tension.

[26] https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract
[27] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[28] https://www.gov.uk/government/publications/net-zero-strategy
[29] https://www.gov.uk/government/publications/energy-and-emissions-projections-2021-to-2040