Department for
Business, Energy
& Industrial Strategy

CONTRACTS FOR DIFFERENCE

Methodology used to set Administrative Strike Prices for CfD Allocation Round 3

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Introduction

This document explains the methodology for determining the Contracts for Difference (CfD) Administrative Strike Prices (ASPs) for Allocation Round 3 (AR3). ASPs represent the maximum strike price a project of a particular technology type in a given delivery year can receive during an allocation round. Should an auction be triggered, ASPs continue to limit how much projects of a particular technology type can receive even if the auction clears at a higher price.

The ASPs presented here have been set in compliance with the methodology approved by the European Commission in its state aid approval for the CfD scheme.[1]

The draft ASPs for less established technologies (those in 'Pot 2') included in the Draft CfD Budget Notice[2] are presented in Table 1 below. Final ASPs will be published in the Final Budget Notice which will be issued no fewer than ten working days before the commencement date of the next allocation round.

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

Technology Type	Delivery Year	
	2023/24	2024/25
Advanced Conversion Technologies	113	111
Anaerobic Digestion (>5MW)	122	121
Dedicated Biomass with CHP	121	121
Geothermal	129	127
Offshore Wind	56	53
Remote Island Wind (>5MW)	82	82
Tidal Stream	225	217
Wave	281	268

[1] http://ec.europa.eu/competition/state_aid/cases/253263/253263_1583351_110_2.pdf
[2] https://www.gov.uk/government/publications/contracts-for-difference-cfd-draft-budget-notice-for-the-third-allocation-round

Section 1: Objectives for setting ASPs

The ASPs set out the maximum support, presented on a price per MWh basis, that the Government is willing to offer developers for each technology in a given delivery year, otherwise known as the reserve price. Should there be sufficient bidders for an auction to be triggered, the clearing price for each delivery year is set by the bid made by the last project allocated a contract in that delivery year before the auction closes, subject to no project receiving a higher strike price than its technology-specific ASP.

The Government identified a number of policy objectives at the outset of the scheme that have framed our approach to setting ASPs: they should be based on robust cost information, set to encourage participation in the allocation round, and set using a consistent approach across technologies. More detail on these three objectives and the implications for how ASPs have been set is included in Table 2, below.

Table 2: Objectives for setting draft ASPs

	Objective	Implications 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.	Use latest evidence on renewable electricity generation costs to produce a supply curve for each technology in each year.
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.	Target 25% of the supply curve when setting reserve prices.
3	**Set using a consistent approach across technologies**	
	The methodology for ASPs should take a consistent approach across all technologies.	Target the same proportion of the supply curve (25%) for each technology.

A key factor is ensuring ASPs are set at a level that encourages new investment. For AR3 the Government has set ASPs at a level whereby projects representing the 25% lowest cost capacity of each eligible technology should be able to participate.[3] This is done based on modelling of ‘supply curves’ for each technology, as set out in Section 3.

[3] For allocation round 2 the proportion was set at 19%

Section 2: Factors considered in setting ASPs

In light of the objectives set out in Section 1, in setting ASPs the Government 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 wholesale electricity prices and the discount which generators may face when signing a Power Purchase Agreement (PPA).

- **Policy considerations** such as the need to drive technology cost reductions and increase value for money for consumers; allowing generators to bid on a non-discriminatory basis and thus targeting the same proportion of the supply curve across technologies. ASPs have also been set to encourage a significant proportion of potential projects to come forward and compete in the allocation round – this level has been set at 25% of the modelled supply curve for each technology.

These factors mean that an ASP for a particular technology is different to the 'levelised cost' – the average cost over the lifetime of the plant per MWh generated. Relative to this levelised cost, an equivalent strike price could be higher or lower for a number of different reasons, all of which are taken into account in the setting of these ASPs:

- **Costs not included in BEIS's standard levelised costs:** CfD top-up payments will be paid on the basis of 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 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. If the CfD contract length of 15 years is shorter than the operating life, and wholesale market revenues and any relevant heat sale revenues 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.

- **Pipeline specific information:** In modelling supply curves for each technology publicly available information relevant to potential bidders in the allocation round has been used to inform cost assumptions for pipeline projects, where possible. As a result, some project cost assumptions may differ from the technology-wide assumptions used in levelised cost estimates.

- **Other relevant information specific to setting ASPs:** This includes policy considerations such as CfD eligibility criteria for each technology (new requirements for Advanced Conversion Technologies and Dedicated Biomass with CHP projects introduced for Allocation Round 3), technology-specific estimates for decommissioning costs and scrappage values not included in BEIS's definition of levelised costs, and other relevant evidence of developments within industry.

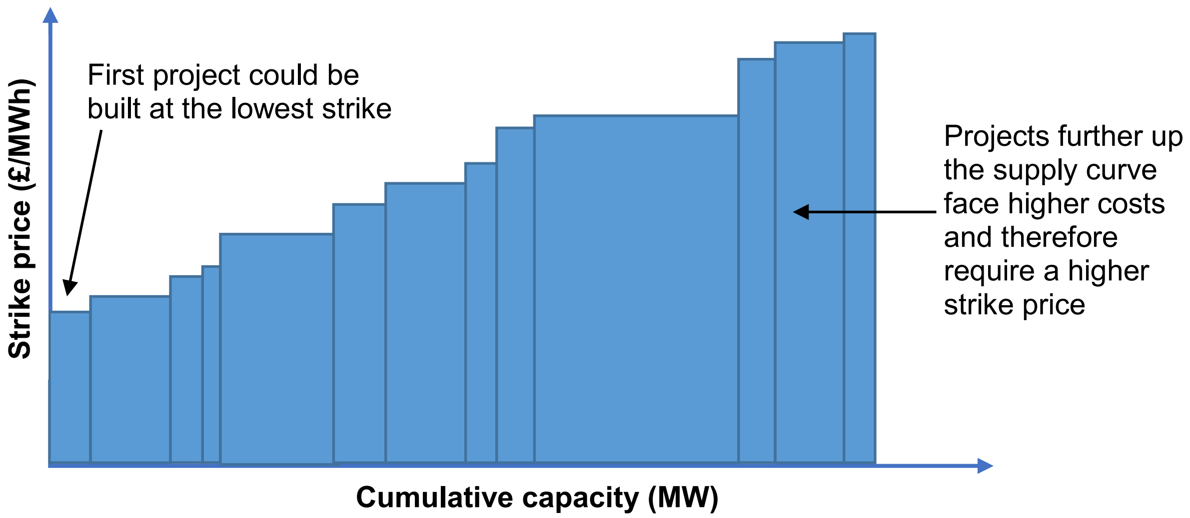
Further, ASPs are set so as to bring forward the most cost-effective projects, which may not be the same as the estimates of typical project costs. For all these reasons, the ASPs presented here may be significantly different from the levelised costs for each technology.

Section 3: Approach to setting ASPs

The methodology for setting ASPs draws on BEIS's latest view on generation costs to produce a modelled 'supply curve' for each technology in each delivery year. 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.

Where possible these supply curves use publicly available information relevant to real-world projects likely to be in a position to bid for CfDs in Allocation Round 3 ('pipeline' projects). Examples include project capacities and estimated load factors based on project characteristics, and are factored in so as to more accurately reflect costs associated with the pipeline.

Figure 1: Illustrative supply curve



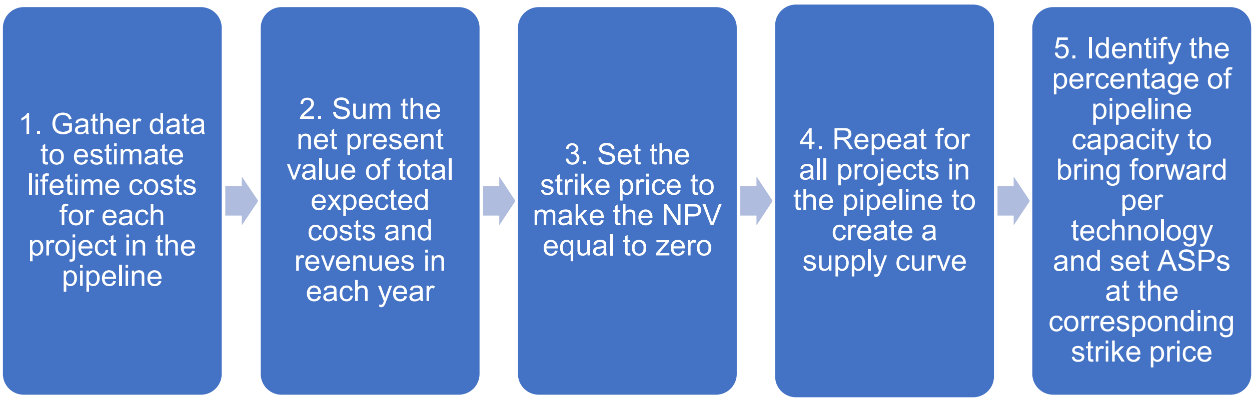
The ASP that is expected to incentivise a certain capacity of deployment is determined through a discounted cash-flow calculation for each project in the supply curve. The 'marginal project' is then identified as the most expensive project within the targeted deployment range (the cheapest 25% of the 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 BEIS's latest view on central hurdle rates.

To ensure a consistent and fair approach, in the absence of sufficient justification for differential treatment, the same proportion of the supply curve has been targeted for all eligible technologies (25%) when setting the 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



3.2 Step-by-step approach

Step 1: Gather data to estimate lifetime cash-flows for each project in the pipeline

Table 3 outlines the key data inputs for estimating project lifetime cash-flows. The primary sources used for these inputs are BEIS's latest view on generation costs and market price projections, supplemented by pipeline project specific information where available. Further details on data sources can be found in Section 5.

Table 3: Key data and assumptions for each pipeline project

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)		

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

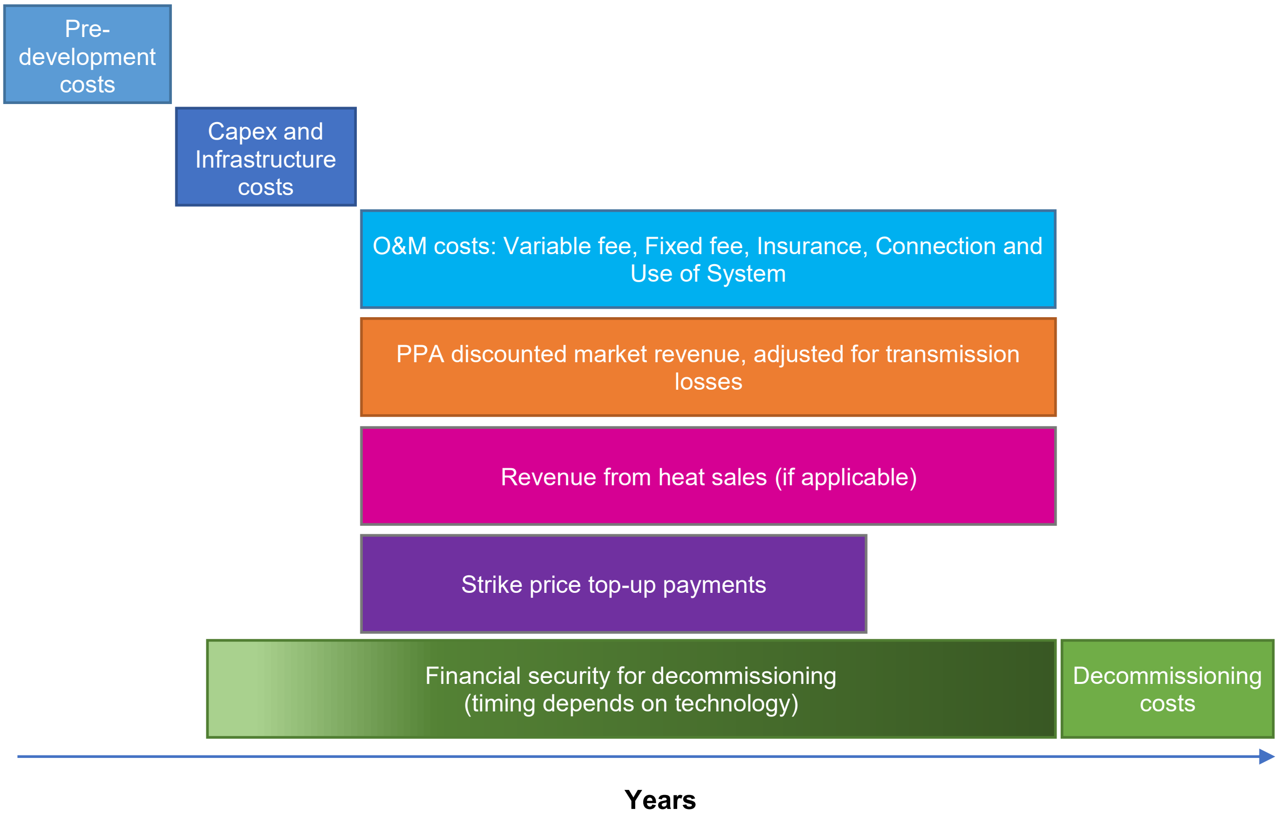
Costs and revenues are summed in each year over the lifetime of the project, and discounted by the hurdle rate for the technology (which accounts for relevant financing costs) to give the net present value (NPV) of lifetime cash-flows:

$$\text{NPV of Lifetime Costs and Revenues} = \sum_{n} \frac{\text{Total capex, opex, decommissioning costs and revenues}_n}{(1 + \text{discount rate})^n}$$

$$n = \text{years}$$

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 BEIS latest view on central hurdle rates.

Step 4: Repeat for all projects in the pipeline to create the supply curve

Where information is publicly available on specific projects in the pipeline the supply curve is constructed from those individual projects, based on bespoke cost and generation assumptions as far as possible.

Where limited information on pipeline projects is available, the range of viable strike prices has been estimated by assuming 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 constant across the length of the supply curve.[4]

Technologies that are grouped together in a single category under the CfD[5] 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 rate

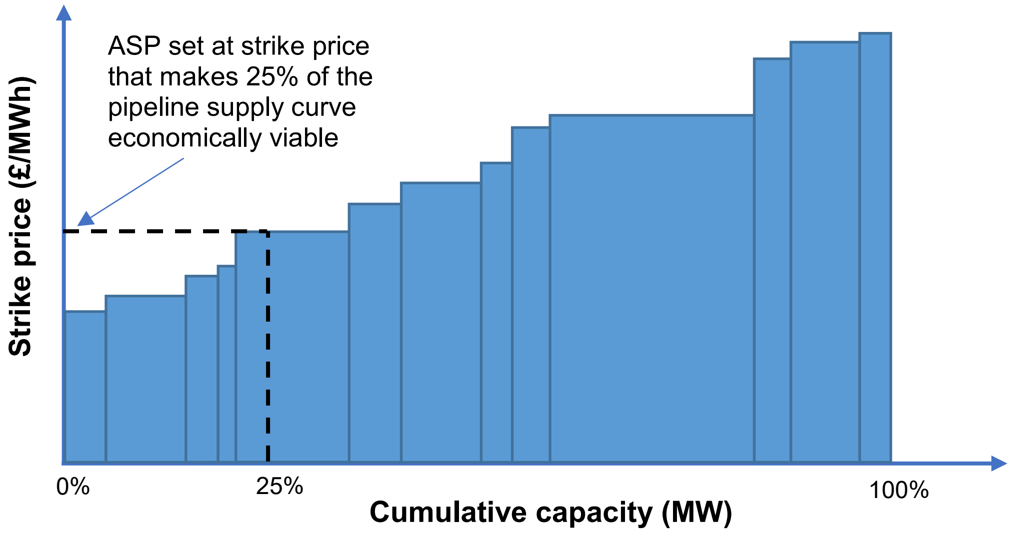
A point on the supply curve is chosen to encourage participation in the auction, ensure competition and fulfil policy objectives. For this allocation round, it has been set at 25% of the supply curve for all technologies, i.e. the ASP for each technology and delivery year corresponds to the strike price that is estimated to make 25% of pipeline projects economically viable, as illustrated in Figure 4. The ASP is then rounded to the nearest £1/MWh.[6]

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

[5] For example, Advanced Conversion Technology (ACT) variants of standard, advanced and with Combined Heat and Power (CHP) are grouped together as 'ACT'

[6] Previously ASPs have been rounded to the nearest £5/MWh but given the level of cost reduction seen and estimated over successive allocation rounds, the Government now deems it appropriate to reduce the level of rounding applied.

Figure 4: Setting the Administrative Strike Price



Section 4: Technology Specific Approaches

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

Offshore Wind and Remote Island Wind

For wind technologies we have constructed supply curves consisting of specific known projects in the pipeline, informed by information included in planning consents. Project-specific costs have been estimated where possible using the following approaches:

- **Project capacities:** These assumptions are based on capacities stated in planning consents.
- **Capex:** Capital costs are assumed to vary with the size of turbine. This is in line with a range of external sources and BEIS's latest view on generation costs. As the MW capacity of each turbine increases, it is assumed that the £/MW capital costs decrease due to economies of scale.
- **Load factors:** These have been estimated using internal models generating power curves (the relationship between the power output of a turbine based on its size, and wind speed) and combining these with site-specific wind speed distribution data from the Met Office.
- **Transmission Network Use of System (TNUoS) charges:** These have been estimated for each pipeline project using tariffs and network charging assumptions for each location, provided by National Grid.
- **Decommissioning costs for offshore wind**: We have used Project-specific decommissioning costs have been estimated using BEIS's decommissioning cost model[7] (developed by ARUP), using project characteristics stated in planning consents.

Advanced Conversion Technologies (ACT)

BEIS's latest view on generation costs are used as the starting point, which for ACT is split into three variants: Standard, Advanced and with CHP, and therefore gives three different supply curves. These variants have been combined based on an assumed breakdown of pipeline capacity. This was informed by reviewing a sample

[7] Cost estimation and liabilities in decommissioning offshore wind installations: https://www.gov.uk/government/publications/decommissioning-offshore-wind-installations-cost-estimation

of pipeline planning consents, and generation cost central project capacity assumptions.

Additionally, a proportion of the cheapest ACT Standard pipeline is excluded from the analysis as they are assumed to be ineligible for a CfD contract given changes to the eligibility criteria for this third round.[8] The proportion that is excluded was again informed by reviewing a sample of pipeline planning applications to determine whether or not they were likely to be able to meet the new eligibility criteria.

Finally, information from the results of Allocation Round 2 (AR2), where ACT cleared at £74.75/MWh in 2012 prices,[9] is incorporated into the supply curve. Based on a review of planning consents for the successful projects, at least one of the projects successful in AR2 will likely be able to meet the new eligibility criteria and therefore it is appropriate to include this value as a point in the ACT supply curve for AR3.

Dedicated Biomass with CHP

As with ACT, clearing price information from AR2 has been incorporated in the supply curve as at least one of the successful biomass projects could potentially meet new standards being introduced for AR3.

Anaerobic Digestion (AD) and Geothermal

Both AD 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 capacity informed by information in the Renewable Energy Planning Database (REPD)[10], the responses to the 2016 Call for evidence on fuelled and geothermal technologies in the Contracts for Difference scheme[11], and project websites. Based on these sources, all projects in the pipeline are assumed to deploy with CHP for both of these technologies, and so only 'with CHP' generation cost estimates have been used.

Tidal Stream

Industry estimates supplied to BEIS on capex and pre-development costs have been incorporated into our modelled supply curve.

Wave

No technology-specific adjustments to generation cost assumptions have been made.

[8] https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme
[9] https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results
[10] https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract
[11] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme

Section 5: Assumptions

The key data source used in setting ASPs is BEIS's latest view on electricity generation costs, which builds on the evidence base from the 2016 Electricity Generation Costs report.[12] 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.

Remote Island Wind is not included as a separate technology from onshore wind in BEIS's generation cost estimates, and therefore Baringa's Scottish Islands Renewable Project Final Report[13] has been used as the primary data source for this technology. These assumptions have been updated in line with cost reductions estimated for onshore wind since 2013, from BEIS's latest generation cost assumptions.

Hurdle Rates

These are sourced from a BEIS commissioned report from Europe Economics (EE), updating the Department's financing cost assumptions for projects starting development from 2018 in a range of technologies.

Connection and Use of System Charges (UoS)

For Offshore Wind and Remote Island Wind, Transmission Network Use of System (TNUoS) charges have been estimated for each pipeline project using forecast tariffs and network charging assumptions for each location, provided by National Grid. For all other technologies, connection and UoS charges estimates are sourced from BEIS's updated generation cost assumptions.

Revenues

Market price assumptions (including forecasts of wholesale prices and PPA discount factor assumptions) have been modelled using the Department's Dynamic Dispatch Model (DDM). Different market prices are assumed to be captured by baseload technologies (such as ACT) compared to intermittent technologies (such as Offshore Wind). These different price series are calculated using generation-weighted average prices captured across CfD Pot 2 intermittent and baseload plants modelled to deploy out to 2050. For baseload technologies this uses the modelled season ahead price. For intermittent technologies, day ahead hourly prices are estimated based on intra-day half-hourly prices.

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

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[12] https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

[13] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/199038/Scottish_Islands_Renewable_Project_Baringa_TNEI_FINAL_Report_Publication_version_14May2013__2_.pdf

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 Call for Evidence on Fuelled and Geothermal Technologies in the CfD Scheme.[14] For all other technologies deploying with CHP heat demand is assumed to be 100% in line with BEIS's levelised cost estimates.

No revenues from the Renewable Heat Incentive (RHI) have been assumed given the scheme is currently due to close to new applicants on 31 March 2021 and so will no longer be a possible revenue stream for generators competing in AR3. No revenues are assumed from the capacity market given State Aid cumulation rules for the scheme during the CfD contract.

Decommissioning costs and scrappage value

For Offshore Wind, decommissioning costs have been estimated for each pipeline project using BEIS's decommissioning cost model[15] (developed by ARUP), using project characteristics stated in planning consents. For other technologies, decommissioning cost assumptions have been informed by information included in planning applications, decommissioning plans submitted to BEIS, independent cost assessments of decommissioning plans (commissioned by BEIS) and internal BEIS 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 BEIS commercial expertise has been used to inform estimates of the cost of these financial securities. Timings of financial securities have been informed from BEIS decommissioning guidance and internal BEIS expertise.

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

Other assumptions

Where project-specific information is available from planning consents for pipeline projects (for example, project capacities and locations) it has been incorporated into the assumptions.

The breakdown of eligible pipeline capacity for technologies with multiple variants in generation cost data (for example Advanced Conversion Technologies) has been sourced from a sample review of planning applications, the Renewable Energy

[14] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme
[15] Cost estimation and liabilities in decommissioning offshore wind installations: https://www.gov.uk/government/publications/decommissioning-offshore-wind-installations-cost-estimation

Planning Database (REPD)[16], the responses to the 2016 Call for evidence on fuelled and geothermal technologies in the Contracts for Difference scheme[17], and project websites.

The AR2 clearing price for ACT and Dedicated Biomass with Combined Heat and Power (£74.75/MWh, 2012 prices)[18] has been included as a data point in supply curves for these technologies, as well as industry estimates supplied to BEIS on pre-development and capex costs for tidal stream, as described in Section 4.

[16] https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract
[17] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme
[18] https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results