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Electricity Market Reform Contract for Difference Call for Evidence Data Validation

CLIENT: National Grid

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Company information

In April 2012 Baringa Partners merged with Redpoint Energy to form an Energy Advisory Services (EAS) practice. The Energy Advisory Services (EAS) practice helps clients across Europe to shape policy, analyse opportunities, build business models and transform performance. Our team specialises in strategy, transactions, finance, energy economics, risk and regulation, market reform and organisational design.

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

In the draft Energy Bill, published in May 2012, the Government set out its requirement that National Grid Electricity Transmission (National Grid), as proposed delivery agent for components of the Electricity Market Reform (EMR) programme, would conduct analysis to support the development of Contracts for Difference (CfDs) for low carbon technologies. In October 2012 National Grid launched a *Call for Evidence (CfE) to support the development of strike prices under Feed in Tariffs with Contracts for Difference (CfD) for Renewable Technologies*[1].

The CfE has been issued to ensure that the most recent and relevant technology costs are reflected in subsequent analysis by DECC and National Grid to inform Government's decision making under EMR, and in particular setting CfD strike prices. The CfE requested data for 27 technologies, and the final validated CfE data set will be considered by DECC alongside the information used in the Renewables Obligation Banding Review (ROBR) published in July 2012 (for which the consultation responses were submitted 12 months ago) and other sources of relevant information including DECC's Onshore Wind Call for Evidence. Data was requested in the CfE for projects commissioning in 2016/17 onwards.

The CfE contained two questionnaires which could be submitted separately by respondents. The first questionnaire concerned costs and technical details, and is referred to here as "quantitative". The second questionnaire sought views on other considerations relevant to investment decisions, and is referred to here as "qualitative".

Quantitative responses

The number of responses to the quantitative section of the CfE was generally quite low, relative to the responses to stages of the ROBR, with a total of 59 responses across 10 of the 27 technologies listed in the CfE. The responses were not evenly distributed: the majority of the responses were for onshore wind (29) and offshore wind (14), with the remaining technologies having four or fewer responses. In the CfE offshore wind projects that are deep and/or far from shore[2] were asked to complete a separate form, Annex B. We have separated offshore wind responses as "offshore wind A" and "offshore wind B" to reflect this difference in response format. For reasons of confidentiality, in this report we have not presented the quantitative data for technologies with 3 or fewer responses.

The completeness of the responses was varied and we have applied our judgement in interpreting the responses given, to arrive at a validated data set. By validating the data in this way we have

[1] *Call for Evidence to support the development of strike prices under Feed in Tariffs with Contracts for Difference (CfD) for Renewable Technologies*, National Grid, 9th Oct 2012
http://www.nationalgrid.com/uk/Electricity/Electricity+Market+Reform/

[2] Offshore wind developments characterised by an average water depth of greater than 45m; or an average distance from shore of greater than 50km; or both, and which are likely to be commissioned from 2016/17 onwards. We note that distance to shore is a crude driver of costs: distance to network connection and distance to supply port may be more relevant.

ensured that the final data set accurately captures the cost estimates that respondents intended to submit to the CfE, removing obvious errors and any basis differences[3].

We have assessed the data quality based on the number of data points received and level of certainty stated by respondents. It should be noted that for most technologies the small dataset limits the weight that should be given to this data when compared to other possible sources.

Note that generation cost assumptions are often project-specific and uncertain for technologies with limited or no deployment. Even among technologies with significant deployment the costs are likely to vary depending on various factors including siting and design choices (such as turbine size or technology choice). Evidence from individual projects is not necessarily indicative of costs for a whole technology group and an overall assessment of levelised costs should consider information all available costs and with a view on the uncertainties and ranges expected.

The sections below summarise the quantitative responses by technology and our key conclusions on the data received.

Onshore wind

A total of 29 responses were received for onshore wind. The data was clear and complete for most questions and we are confident we have captured the responses as intended by respondents. There was a reasonably large spread of values for all costs, perhaps reflecting the variations in site and location of the projects described. We believe that this could be used to guide the derivation of levelised costs, but that other sources should be sought, especially for hurdle rates.

Some of the key comparisons to the ROBR are as follows. The median value for total capex is 10% higher than the ROBR median. Total opex is higher by 63%. Contributing factors to this increase may include transmission charging and the labour costs. A number of respondents commented that a shortage of specialist technicians was increasing maintenance costs.

Load factors are similar, though are difficult to compare due to a lack of geographical granularity. Only 6 responses included hurdle rates, and there was not enough clarity in these responses to draw any meaningful conclusions on likely hurdle rates.

Offshore wind A

A total of 7 responses were received for offshore wind A. We received a reasonable number of data points and assessed that the responses were submitted as intended, without error.

It is difficult to compare the CfE data (categorised by distance and depth) to the ROBR data, which is categorised as R2 or R3. Respondents were responsible for selecting the CfE category for their project. Offshore wind A appears to include data from both R2 and R3 projects, however the data available did not allow for re-categorisation along these lines.

Notwithstanding this caveat, the median total capex is higher than the ROBR (32% higher than the ROBR R2 median values and 5% higher than the ROBR R3 median values). Total opex is

[3] We have not validated the underlying calculations made by respondents in populating the values in their responses. We contacted a limited number of respondents (via National Grid), where clarification of major cost elements was required.

higher than the ROBR benchmarks. The median load factor for offshore wind A was 44%, higher than the ROBR median values of 38% and 40% for R2 and R3 projects respectively.

There is a high level of uncertainty stated by respondents and therefore caution should be used in using this dataset to model levelised costs for the purpose of setting strike prices. We believe that the CfE figures presented here could be used in conjunction with other sources when deriving levelised cost estimates, noting the difficulties in combining data sets due to the offshore wind A/B vs. R2/R3 category mappings.

Offshore wind B

A total of 7 responses were received for offshore wind B. We received a reasonable number of data points and assessed that the responses were intended. We believe all offshore wind B responses are likely to be for R3 projects.

The median value for total capex is higher than the ROBR, e.g. capex for far from shore/deep projects is 13% higher than the ROBR R3 values. Total opex is higher than the ROBR benchmarks. Load factors are significantly higher than the ROBR e.g. for far from shore/deep projects is 44% vs. 40% for ROBR R3.

There is a high level of uncertainty stated by respondents and therefore caution should be used in using this dataset to model levelised costs for the purpose of setting strike prices. The number of responses reflects the relatively small number of the players developing deep/far from shore offshore wind. We believe that this, combined with the level of uncertainty stated by respondents, and the wide variation in project specifics, limits the confidence in these values. The cost data presented here should be only one factor in any consideration of costs and should be given limited weight alongside other sources.

Tidal Stream

A total of 4 responses were received for tidal stream. It was not clear from responses whether these projects align to the ROBR shallow or deep tidal stream categories, though we believe these are likely to be shallow water as they refer to early round projects.

Total capex is much higher (43%) than the ROBR values for tidal stream shallow and somewhat higher (7%) than the values for tidal stream deep. Opex is slightly higher than ROBR values for tidal stream shallow (4%) and tidal stream deep (15%). The cost data presented here are a useful guide but should be only one factor in any consideration of costs and should be given limited weight alongside other sources due to the low number of responses.

Wave

A total of 4 responses were received for wave. We validated the responses and are confident that they clearly represent the views of the small number of respondents. Though the number of responses reflects the relatively small number of the players in the market of this early stages technology, we do not believe there is sufficient data to give a robust estimate of costs.

The major drivers for overall levelised cost differ significantly from the ROBR values. The median value for total capex is much higher (79%) than the median ROBR value. The median opex is slightly lower than the ROBR (-8%).

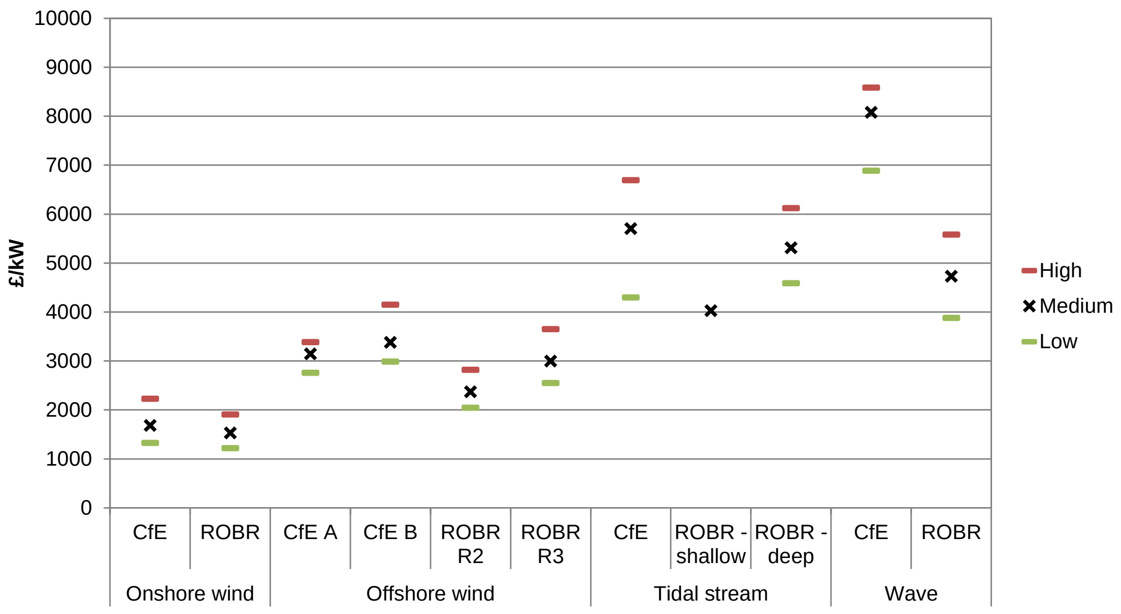
There was a large range in some of the costs, which was attributed by respondents to project location. The cost data presented here are a useful guide but should be only one factor in any consideration of costs and should be given limited weight alongside other sources.

Summary of Capital Costs

Figure 1 shows the total capital costs (the sum of pre-development costs and construction costs, excluding Interest During Constructions (IDC)) for each technology and the values for comparison from the ROBR. This is one of the key drivers of levelised costs (others are opex, load factor, investment lifetime and hurdle rate).

Overall, the costs submitted by respondents appeared to be higher on average than recent benchmarks such as the Renewables Obligation Banding Review (ROBR) and, for offshore wind, the Crown Estate Cost Reduction Pathways study. This may reflect near term cost pressures, such as higher commodity prices, lower sterling exchange rates or supply chain constraints and higher labour costs, as well as the fact that some of the easier sites have already been developed, though without a full study it is difficult to verify these factors. The CfE responses suggest that labour costs and the lack of maintenance technicians is a large driver of costs at the moment and is anticipated to be in the future.

Figure 1 – Comparison of total capital costs



The CfE also asked respondents for their views on the future direction of capital and operational costs, and the drivers for these changes.

Respondents generally thought that costs will go up, except for technologies which are at an early stage of deployment and where learning is expected. Respondents suggested that the main drivers for increases are expectations of increasing commodity prices and unfavourable exchange rates.

Respondents for marine technologies (wave and tidal stream) expected costs to decrease, due to technology learning and the economics of deploying future projects at larger scale. For offshore wind, there was an even split between those who thought capital costs and operational costs would increase and those who thought they would decrease.

Qualitative responses

Respondents were also asked a number of qualitative questions, shown in Table 1. There were 39 qualitative responses to the CfE. Of these, 10 submitted qualitative responses only and 29 respondents completed qualitative and quantitative responses. Responses were received from a mixture of parties, including five of the six large vertically integrated energy companies, alongside independent and merchant generators.

Table 1 – Qualitative questions

Question number	Question text	Key message from responses
A	*"Please state whether the technology costs assumptions made through the ROBR (see Appendix A) are applicable for CfD strike price setting for projects commissioning from 2016/17 onwards."*	The 16 responses were generally aligned with their quantitative cost estimates, where they had submitted these. Whilst some respondents thought that the ROBR cost estimates were applicable, at least for particular costs, more respondents thought that the ROBR cost estimates were too low. We have used this as a check on the observed differences between CfE and ROBR quantitative results.
C(i)	*"Please state what levels of reduction in hurdle rate you believe are likely in percentage points [or basis points] in pre-tax real terms [or specify if in other terms] for projects which are supported by CfDs."*	Very few respondents gave the percentage change in hurdle rates that they anticipated for projects supported by CfDs. Respondents cited a lack of knowledge about the details of the CfD arrangements. This may be rectified somewhat by the Energy Bill and supporting documents, which respondents may not have fully reviewed in the available timeframes.
C(ii)	*"Please outline any factors that could mean the wholesale prices obtained on the market for renewable technologies may be systematically different from potential CfD reference prices (e.g. due to the load profile of generation being concentrated at times of higher or lower wholesale prices)."*	Of the 28 respondents, 24 respondents believed that there were factors that could result in a difference between the wholesale prices obtained on the market and the potential CfD reference prices. These included short term price risk and balancing risk which are closely linked to the level of discounts in Power Purchase Agreements. Potential reforms to liquidity and electricity cash-out will also have a bearing on PPA discounts.

Question number	Question text	Key message from responses
C(iii)	*"Please comment on the likely factors that will influence take-up potential of CfDs as opposed to ROCs, which specific projects the stakeholder is likely to prefer under the CfD scheme and the factors that influence such decisions, e.g. would choice depend on:* *Straight financial calculations (the difference in project NPV)* *Developers' and financial institutions' knowledge and experience of the two mechanisms* *Any risk of missing the last date for accreditation under the RO* *Any possibility of FID-enabling products being available* *Or other factors"*	Respondents mentioned a range of factors, including those listed in the question and others factors. A benefit of CfDs that was regularly highlighted was 'avoiding volatility'. Some respondents took the view that CfDs reduce uncertainty when compared with ROCs because the received price is more stable. On the other hand ROCs were viewed by some respondents as less risky because there is an obligation upon suppliers to buy "renewable power"/ROCs. This was seen as beneficial compared to CfDs, where there is nothing enforcing the purchase of renewable electricity. This is closely related to the issue of PPA availability and discounts.

Respondents also used the CfE as an opportunity to raise a number of concerns with the CfD arrangements:

- *A perceived lack of clarity about CfD arrangements*. This was cited as a reason for being unable to provide full answers to the specific qualitative questions. This may have since been addressed somewhat by the publication of the Draft Energy Bill and supporting documents in November 2012, which respondents may not have fully reviewed within the available timeframes of the CfE.
- *CfD support length of 15 years*. Some respondents were concerned that as projects would likely have investment lifetimes of 20 or 25 years this will expose the project to wholesale price risk in the final 5 or 10 years. Although under the RO generators will have power price risk for the 20 year period, they still have a high amount of certainty around ROCs and this is a significant proportion of revenues, particularly for offshore wind. When setting CfD strike prices, DECC will need to consider whether or not to assume a residual value for the asset after 15 years, and how investors may view this residual value.
- *Transition between RO and CfDs.* Some respondents held the view that the pace of the transition should be slowed and the RO extended. This appeared to be closely linked to the perceived lack of clarity about the CfD arrangements.
- *Intermittent generation.* Responses regarding onshore and offshore wind mentioned the risk that intermittent generators would not be able to achieve the CfD reference price due to short term price risk and balancing risk and so in total would receive lower than the CfD strike price. These are the same factors as those that will drive PPA discounts and therefore should be considered alongside these when setting CfD strike prices.

- *Treatment of Power Purchase Agreements (PPAs).* A large number of respondents were concerned about the lack of competition amongst buyers in the market for long term PPAs and how this may affect the ability to finance CfD projects. The impact of competitive dynamics in the PPA market may be transitory compared to other effects that drive PPA discounts.
- *Northern Ireland.* The higher expected level of curtailment and the different market arrangements for compensation of curtailment were raised by respondents with regards to projects in Northern Ireland. The unknown impact of future changes to the Single Electricity Market (SEM), mandated by the European Target Model, was also raised as a concern.

Taken as a whole, the CfE responses suggest that the costs of renewable generation have not reduced since the ROBR and that short term pressures may well have pushed some costs up. The uncertainties about how financing and contracting would work under CfDs in the absence of real projects means that the CfE has not provided conclusive evidence in this respect.

2. INTRODUCTION

2.1. Background to Call for Evidence

In the draft Energy Bill, published in May 2012, the Government set out its requirement that National Grid Electricity Transmission (National Grid), as proposed delivery agent for components of the Electricity Market Reform (EMR) programme would conduct analysis to support the development of Contracts for Difference (CfDs) for low carbon technologies. In October 2012 National Grid launched a *Call for Evidence to support the development of strike prices under Feed in Tariffs with Contracts for Difference (CfD) for Renewable Technologies*[4]. The Call for Evidence (CfE) closed on the10th December 2012 for quantitative responses (responses to Annex A cont'd and Annex B of the Call for Evidence) and on the 7th January 2013 for qualitative responses (responses to Annex A and Annex C).

The CfE has been issued to ensure that the most recent and relevant technology costs are reflected in subsequent analysis by DECC and National Grid to inform Government's decision making under EMR, and in particular setting CfD strike prices. The data gathered through the CfE, requested for 27 renewable generation technologies, was considered alongside the information used in the *Renewables Obligation Banding Review*[5] (ROBR) (for which the consultation responses were submitted 12 months ago) and the *Crown Estate Offshore Wind Cost Reduction Pathways Study*[6]. DECC will use this information in conjunction with other ongoing data gathering exercises (e.g. the *Onshore Wind Call for Evidence*)[7]. Data was requested in the CfE for projects commissioning in 2016/17 onwards.

Baringa was engaged by National Grid to analyse and assess the CfE submissions. This involved cleansing of the responses, assessing the quality of the data, providing summary statistics of quantitative responses by technology, interpreting the data and summarising qualitative data and comments. The quantitative summary statistics together with our assessment of the data set's robustness will be used by DECC, along with other recent studies into renewable generation costs, when setting CfD strike prices.

2.2. Structure of Call for Evidence

The Call for Evidence contained two questionnaires. These could be submitted separately by respondents, and had different deadlines for submission. The first questionnaire concerned costs and technical details, and can be characterised as "quantitative". The second questionnaire dealt

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[4] *Call for Evidence to support the development of strike prices under Feed in Tariffs with Contracts for Difference (CfD) for Renewable Technologies*, National Grid, 9th Oct 2012 http://www.nationalgrid.com/uk/Electricity/Electricity+Market+Reform/

[5] *Renewable Obligation Banding Review,* DECC, 15th July 2012

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66180/Renewables_Obligation_consultation_-_government_response.pdf

[6] *Crown Estate Offshore Wind Cost Reduction Pathways Study,* The Crown Estate, May 2012

http://www.thecrownestate.co.uk/media/305094/Offshore%20wind%20cost%20reduction%20pathways%20study.pdf

[7] *Onshore Wind Call for Evidence*, DECC. 15th November 2012

https://www.gov.uk/government/consultations/onshore-wind-call-for-evidence--2 with investment decisions, and can be characterised as "qualitative". Questionnaire 1 had three parts: Annex A, Annex A cont'd, and Annex B. Annex B contained questions specific to deep or far offshore wind[8], and was completed instead of Annex A cont'd for this technology. Throughout this report we refer to Offshore wind A to represent responses to Annex A cont'd, and Offshore wind B to represent responses to Annex B. The original list of technologies provided in the CfE can be seen in Table 3.

Table 2 - CfE Technologies, as provided in the CfE document Oct 2012

Technology
Onshore wind > 5 MW
Offshore wind R2
Offshore wind R3
Biomass conversion / enhanced co-firing
Dedicated biomass < 50 MW, Dedicated biomass > 50 MW, Dedicated biomass CHP
Standard co-firing, Co-firing with CHP
Hydro > 5 MW without storage, Hydro > 5 MW with storage
Wave
Tidal stream shallow, Tidal stream deep
Geothermal, Geothermal CHP
PV > 5 MW
AD, AD CHP
Standard ACT, Advanced ACT, ACT CHP
Bioliquids, Bioliquids CHP
Energy from Waste, Energy from Waste CHP
Landfill gas, Sewage gas

[8] Offshore wind developments characterised by an average water depth of greater than 45m; or an average distance from shore of greater than 50km; or both, and which are likely to be commissioned from 2016/17 onwards.

Table 3 describes the question structure of the Call for Evidence further:

Table 3 - Call for Evidence questionnaire structure

Questionnaire	Part	Annex	Covers	Technology
1	i	A	Technology Cost Assumptions and Maximum Build Rates	All
1	ii	A cont'd	New Technology Costs data supported by evidence	All, except deep or far offshore wind
1	iii	B	Deep Water, Far from Shore Offshore Wind Costs	Deep or far offshore wind
2	-	C	Investment Decisions under CfD	All

The Call for Evidence was published with a desired template for all responses, in the form of an Excel spreadsheet containing all CfE questions. Many respondents sent in responses using this template, though a number used non-standard Excel sheets, PDF documents, and covering emails. Effort has been made to ensure all response information has been captured, regardless of response medium.

Our report document is structured as follows:

- In Section 3, we provide an assessment of the quantitative data
- In Section 4, we provide an assessment of the future trends in cost drivers
- In Section 5, we provide an assessment of the qualitative responses
- In Appendices A, B and C we present respectively: all technology specific data tables, data benchmarks, and Northern Ireland specific data tables

3. ASSESSMENT OF QUANTITATIVE RESPONSES

3.1. Approach to quantitative data

Our approach to the assessment of the quantitative data comprised of two stages: the Analyse stage, followed by the Assess stage.

3.1.1. Analyse stage

In the Analyse stage we undertook detailed analysis of the collated data received under Annex A cont'd and Annex B of the CfE responses. This was broken down into two tasks: data cleansing and data summarisation. Data cleansing involved going through the collated dataset received from National Grid, alongside the collation summary and individual email responses, to ensure that any errors, such as non-standard units, currency or monetary terms were corrected. We also ensured that data was consistent.

It should be noted that quantitative responses were not always consistent in the way they were submitted, particularly with regard to the units. Due to the relatively low number of responses it was feasible to check manually all entries to ensure consistency, but had there been a larger number of submissions this may have proven difficult within the project timeline.

Once the data had been cleansed and was considered to be in a consistent format, the key summary statistics for each parameter were calculated (Number of responses, Min, Max, Mean, Median, $10^{th}/90^{th}$ percentiles).

3.1.2. Assess stage

During this stage, we assessed the quality of the data received and provided interpretation of the range in values for the parameters, further adjusting and correcting quantitative responses where necessary to ensure consistency.

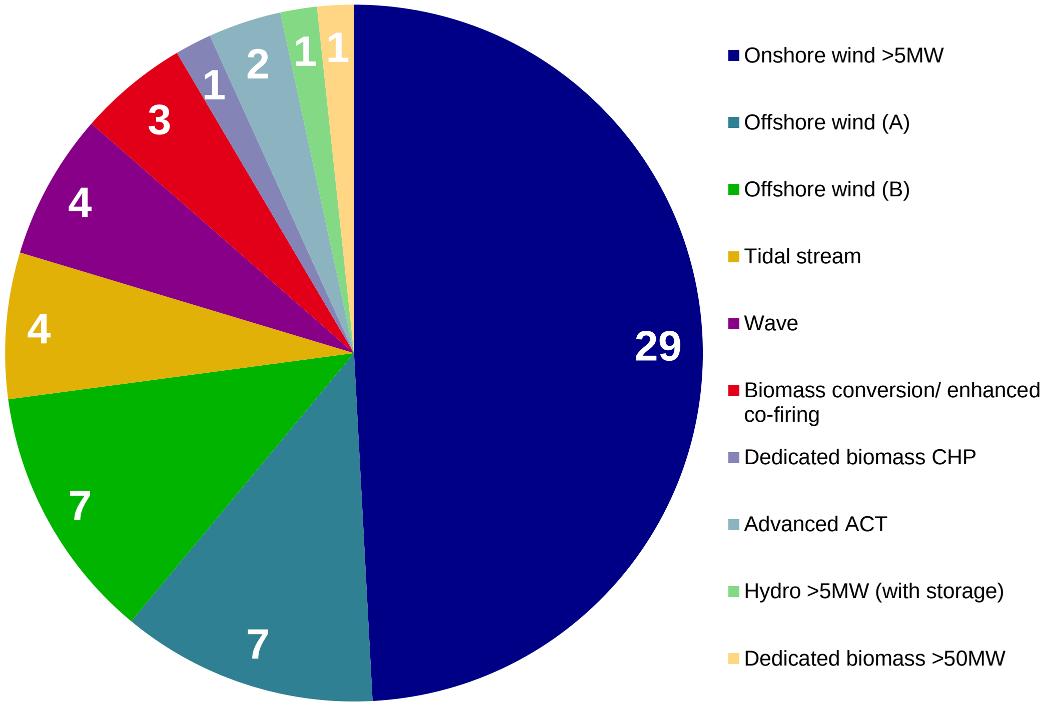
The CfE requested cost estimates for projects starting operation after 2016. Most responses were for projects starting in 2017 / 2018, though a small number (1 onshore wind, 1 offshore wind A) were for projects beginning construction in 2012 / 2013 and beginning operation before 2016. In both cases the respondents stated they had adjusted costs as necessary to reflect projects commissioning after 2016, and so the values submitted were used unadjusted. One respondent highlighted that costs were inflated but did not provide the indexation and another stated that they did not foresee any change in costs for a project commissioning after 2016. They explicitly stated that costs were valid and so these were taken without alteration.

As part of the Assess stage, we compared the final assessed data to other sources of cost estimates: the Renewable Obligation Banding Review, and the Crown Estate Cost Reduction Pathways Stud*y.*

3.2. Summary of quantitative responses

In total, there were 59 responses to the quantitative part of the CfE (excluding the four excluded responses described below). These were not evenly distributed between the technologies; of the 27 technologies listed in the CfE, there were no responses for 17 of them, with the responses submitted falling under 10 categories. Figure 2 shows the breakdown of the quantitative data received, by the different technologies[9].

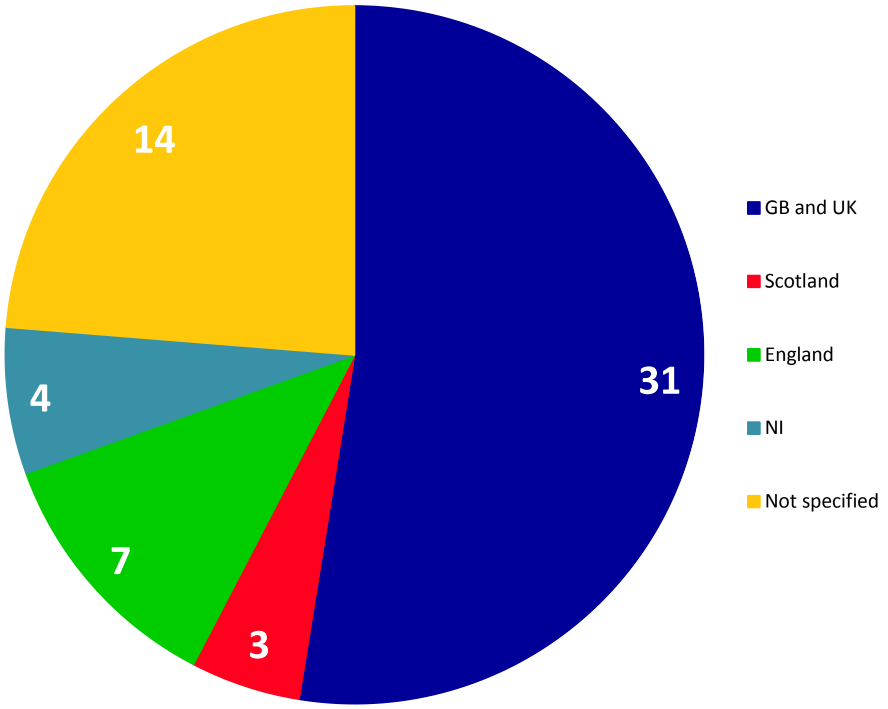
Figure 2 - Summary of data received, by technology



We have also summarised the quantitative data received by region in which the project is located (Figure 3), although we note that the region information is far from complete. In cases where respondents did not provide the region to which their response was referring (15), these have been categorised as 'not specified'. The category 'GB and UK' has been used where the respondents specified either GB or UK when asked to which region they refer.

[9] It should be noted that it this report we have not presented the quantitative data for technologies with 3 or fewer responses to preserve the confidentiality of data provided by individual respondents.

Figure 3 - Summary of data received by region



Data completeness

The data received did not provide complete costs estimates for all projects, with very few respondents answering all questions. Although most respondents provided at least some answers in each section, many cost categories were consolidated and subtotals submitted rather than the individual items asked for in the questions. In a number of cases respondents stated that the reason for this aggregation was due to commercial sensitivity surrounding the figures.

Most respondents provided responses covering pre-development costs, construction costs and operational costs. Areas that were less well covered included hurdle rates and levels of debt financing.

3.3. Changes made to the quantitative data

When assessing the data quality, we:

- Mapped responses onto technology categories described in the CfE document. Offshore wind was categorised using "A" or "B" to signify if the response had completed Annex B for deep or far offshore wind. Note these categories do not align specifically to the "Round 2" and "Round 3" categories in the ROBR and we would expect there to be some overlap.
- Checked that all offshore wind responses had completed the correct annex for the type of project being described. Two respondents had completed both Annex A and B for deep offshore projects, with very similar cost data in each annex. In this case the technologies were categorised as "offshore Wind (B)" and the responses in Annex A were ignored.

- Ensured all responses were in scope. Two responses referred to technologies that were out of the scope of the CfE, namely “onshore wind < 5 MW” and “hydro < 5 MW”, and were omitted from the analysis.
- Removed duplicated data. Two identical responses were received from a joint venture; the quantitative data from one response was ignored, though the comments were included in the qualitative analysis. One respondent submitted identical responses for two projects starting in 2016/17 and 2017/18 respectively; only the former was included in the analysis. Two offshore wind responses were found to be identical, and so one was ignored.
- Removed Offshore Transmission Owner OFTO costs from construction costs. Some Offshore wind generators may follow the ‘generator build’ option for the offshore connection. However, this would be transferred to an OFTO and the generator reimbursed for these costs. The costs are recovered from the generator as a local asset charge in their Transmission Network Use of System (TNUoS) charge. We have included OFTO costs in operational charges instead.
- Contacted a limited number of respondents (via National Grid), where clarification of major cost elements was required.
- Where there was a large range between different respondents’ data, considered the reasons for this difference, assessing whether there were mistakes leading to the difference.
- Ensured that hurdle rates were re-based in pre-tax real terms (as requested in the CfE) where they were not provided on this basis.
- Aggregated cost data into subcategory totals costs (pre-development, construction, operational – variable operation and maintenance (VOM) and fixed) due to lack of data at finer granularity. Many respondents did not fill in all questions, but gave aggregated cost figures. Where possible these have been separated but in most cases this was not possible.
- We have assumed that submitted costs are in real 2012 terms unless otherwise stated.

3.4. Explanation of cost parameters

The costs and other information asked for in Annex A cont’d and Annex B are explained in Table 4. This shows the groups we have used to categorise costs and what we have included in each group. The categorisation has been chosen to provide output data at the highest level of robustness. Respondents did not all provide the same parameters when costs are viewed in more detail.

Respondents presented the components of opex in a range of different ways. Some provided only the total values, whereas others provided a breakdown at varying levels of detail. As a consequence of this, we have presented the total opex values only (the sum of all fixed and variable costs), as these are the most robust values. For comparison purposes, we have performed the same aggregation on the ROBR data. Where provided, we have presented VOM separately, alongside total opex.

As highlighted in Section 3.3, OFTO construction costs have not been included in capital/construction costs. Instead, annuitised OFTO charges have been included in opex figures.

From the questions asked in the CfE, all of the cost parameters have been covered in our analysis, except the following: reduction in hurdle rates and level of debt finance are not included because not enough of the respondents provided information on these. For example, on expected debt finance, only 4 respondents provided a % value; most did not answer and some stated that it is not known.

Table 4 - Explanation of costs and technical parameters

Cost/Information Asked	Units	Explanation/What it Includes
Pre-development costs	£/kW	Pre-licensing Technical development costs Planning
Pre-development period	Years	Length of time taken for pre-development
Construction costs	£/kW	Cost of construction including procurement and project management Grid connection costs (excluding OFTO) Other infrastructure costs
Construction period	Years	Length of time taken for construction
Total opex	£/kW/year	Fixed O&M costs Insurance costs Connection and use of system charges Variable O&M costs
of which VOM	£/MWh	Variable O&M costs only
Operational lifetime	Years	Length of time the plant is expected to be in operation for
Expected investment period	Years	Payback period for investment
Availability	%	Amount of time the plant is available to generate power, ie when not on outage
Load factor (Net)	%	'Net load factor' refers to the amount of power the plant will generate in a year as percentage of its maximum capacity, after accounting for plant availability
Plant Capacity	MW	Size of the plant
Hurdle Rate (Pre-tax real)	%	Required return on investment

In the following sections we summarise the responses received for the individual technology categories. We have not included quantitative data for those technologies receiving 3 or fewer responses, to ensure the confidentiality of commercial data received through the Call for Evidence. We have presented quantitative data for onshore wind, offshore wind (A), offshore wind (B), tidal stream, and wave technologies only. The tables provided in this section include low, medium and high values from the CfE and ROBR, for the technologies listed above. The low, medium and high levels refer to the 10^{th}, 50^{th} (i.e. median) and 90^{th} percentile values in both studies. Where there were insufficient number of responses to precisely give a percentile value, this was calculated by weighting the nearest available response values, as per Excel's "Percentile.Inc" function.

3.5. Onshore wind

There were 29 responses for onshore wind, from 13 respondents. A number of respondents submitted responses for multiple projects. When multiple responses were received from respondents, the data was checked to ensure it was referring to different projects of sufficient variation to warrant being included in the CfE analysis. All responses were deemed unique in this respect and were included in the analysis. The onshore wind plant capacities in the CfE ranged from 5 MW to 100 MW with a mean of 36 MW.

Table 5 summarises the onshore wind data and compares the results to the ROBR median. The full data summary, for all technologies, can be found in Annex A.

Table 5 - Onshore wind summary statistics

		CfE				ROBR		
		Mean	L	M	H	L	M	H
No. CfE Responses	-	*29*						
Pre-development costs	£/kW	92	33	84	161	21	32	110
Pre-development period	Years	6	4	6	8			
Construction costs	£/kW	1628	1295	1600	2068	1200	1500	1800
Construction period	Years	2	1	2	2		2	
Total opex	£/kW/year	64	43	64	84		39	
of which VOM	*£/MWh*	*10.0*	*3.7*	*10.6*	*18.6*		*3.0*	
Operational lifetime	Years	24	20	25	25		24	
Expected investment period	Years	22	20	24	25			
Availability	%	97%	95%	97%	97%			
Load factor (Net of Availability)	%	29%	27%	30%	31%		29%*	
Plant Capacity	MW	36	10	30	76			
Hurdle Rate (Pre-tax real)	%	12%	10%	12%	15%			

* N.B. There is not enough granularity in responses to breakdown load factor by the different regions so we have taken the average of the 3 load factors provided in the ROBR.

3.5.1. Pre-development costs

The pre-development costs for onshore wind ranged from a low of 33 £/kW to a high of 161 £/kW from 24 responses, with a median of 84 £/kW. This is significantly higher than the ROBR pre-development cost median value of 32 £/kW. The maximum pre-development costs submitted by any respondent was 210 £/kW and this respondent commented that previous studies significantly underestimated the costs incurred during the planning phase, and that these costs were likely to increase over the period 2013-2016 due to increases in the number of planning applications going to appeal. A number of respondents stated that there was likely to be upward pressure on pre-development costs, due to perceived increases in planning hurdles, and because the most suitable sites had already been used. To the extent that responses incorporate views of future changes in costs, there is an additional source of uncertainty in these values. However, these values reflect respondents' best views given this uncertainty.

The median pre-development period submitted was 6 years, ranging from 3 to 9 years from 29 responses.

3.5.2. Construction costs

The median CfE construction cost (1600 £/kW from 27 responses) was higher than the ROBR median of 1500 £/kW. There was a large range in construction costs in the CfE from a low of 1295 £/kW to a high of 2068 £/kW. The following factors were mentioned as drivers of construction costs: near term cost pressures, such as higher commodity prices, lower sterling exchange rates and supply chain constraints.

The onshore wind construction period ranged from 1 to 3 years, with a median of 2 years. This is consistent with the median construction period from the ROBR.

The project with the minimum construction costs also had the minimum pre-development costs. There was not enough detail in the response to interpret why this project may have lower costs than an average project. However, the responses gave us no reason to doubt that these were the numbers intended. Regional variations may have contributed towards the range in responses since the response with the highest costs (2796 £/kW) refers to a project in the highlands of Scotland – where remoteness is likely to push up construction costs. The minimum and maximum costs are not considered outliers, as the remaining responses did not all cluster around the mean, and were spread fairly evenly within the range. Given that there are good reasons for a range in these response values, we can be reasonably confident that the overall dataset accurately reflects the views of respondents. We note that the data range is similar to the ROBR.

3.5.3. Operational costs

Operational costs ranged from a low total opex of 43 £/kW/year to a high of 84 £/kW/year, from 27 responses. The median is 64 £/kW/year. This is higher than the ROBR median of 39 £/kW/year. Variations in TNUoS may have had a large impact on the CfE numbers, and explain some of the large range in responses. TNUoS costs vary from approximately 27 £/kW in Scotland to negative costs in some parts of the South of England. For onshore wind, connection and UoS charges did range from answers of 0 £/kW or N/A to a maximum of 15.5 £/kW. A number of responses were submitted with additional line items which we have included in the total opex costs (business rates, telecommunication, community fund and "other"). A number of responses included land rates as a separate line item. After discussion with DECC these were not included so as to be consistent with previous ROBR calculations.

A number of respondents commented that a shortage of specialist technicians was increasing maintenance costs. This may be a recent effect contributing in some part to the higher total opex in the CfE compared to the ROBR. The consideration of whether this shortage of maintenance technicians is a short term effect or is likely to continue over the lifetime of the assets explored in further detail later in this report. Section 4.2 shows how 19 respondents highlighted labour costs as a key cost driver and were concerned that a lack of labour is meaning labour costs are high and form a large part of operational costs. The key conclusion is that labour costs and the lack of maintenance technicians is a large driver of costs at the moment and is anticipated to be in the future. VOM was presented separately for 11 responses. Of these, the median was £10.6/MWh.

This is higher than the ROBR median of £3/MWh. It is not clear what the reason for this difference is. The range for VOM was from a low of £3.7/MWh to a high of £18.6/MWh. The main constituent of total opex (where given) was the fixed element of maintenance. The VOM figures were provided by a subset of respondents (11 responses, compared to 27 for total opex) and therefore total opex values should be considered as the key results.

3.5.4. Technical assumptions

The median load factor for onshore wind was 30% with the range being from a low value of 27% to a high of 31%. For reference, the ROBR median load factors are 25.5% for England and Wales, 28.6% for Scotland, and 33.3% for Northern Ireland, based on historical averages. There was not sufficient granularity of regions in CfE responses to make a region-by-region comparison.

The median operational lifetime was 25 years for onshore wind, slightly above the median value of 24 years from the ROBR. For onshore wind, as with the other technologies, operational lifetime aligned rather closely to expected investment period (24 years for onshore wind). The range for operational lifetime estimates was fairly tight, with a minimum of 20 and maximum of 25 years. It seems that with operational lifetime, for onshore wind and for the other technologies, respondents gave a standard answer of either 20 or 25 years: of the 23 onshore wind respondents providing operational lifetime, all except 2 gave either 20 or 25 years as their answer. The remaining participants gave 22 and 24. Given this range, we believe that the ROBR value of 24 years is still appropriate.

3.5.5. Financial assumptions

Hurdle rates were provided by only 6 respondents, ranging from 10% to 15% with a median of 12%. Hurdle rates were converted to pre-tax real terms where explicitly presented differently, but were assumed to be in pre-tax real terms if not specified (as was asked in the question). The wide range in hurdle rates may be due to some responses being presented on a different basis and it not being specified in the response. There was no ROBR hurdle rate data to benchmark the CfE against for onshore wind.

The median expected investment period was 24 years, from 20 respondents. There was a large range in the values presented, from 10 to 25 years. As with operational lifetime, many respondents (9) submitted 25 years as the expected investment period and many others (7) submitted 20 years, with the remaining submitting somewhere in between. There was 1 exception: the minimum response of 10 years was half the next lowest, and much lower than would be typical for an onshore wind project. The respondent who submitted the 10 year figure commented ‘debt funding does not currently go beyond 10 years’. We assume that they were making the point that the project would need to be refinanced during the project life given the lack of availability of long-term debt, rather than expecting an investment period of 10 years.

The expected investment period of 24 years for onshore wind, as will also be seen for the other technologies, is much longer than the 15 years of support offered with CfDs. This was something that respondents regularly commented on and is discussed in detail in the qualitative part of this report (see Section 5.7.2).

3.5.6. Summary

Onshore wind had the highest number of responses (29) of any of the CfE technologies. This number is large enough to give a reasonable level of confidence that the results are robust to the impact of any outliers. Although there is a large range in some of the summary statistics (pre-development costs, construction costs), the responses were clear and complete. The large range appears to be due to variations between projects as the costs did not cluster around the means, and were spread fairly evenly amongst the range. The range of projects could reflect the diversity of projects in the UK, for example with capacity ranges from 5 MW to 100 MW and load factors from 27% to 33%. These load factors are within a reasonable range for the UK, but we cannot make robust statements about the regional breakdown from the data received. In our view, other sources such as wind speed data or historic regional load factors should be used to derive this variation. We note that the largest project capacity received in the CfE was 100 MW, whereas there are a number of onshore wind farms in the development pipeline which have larger planned capacities.

We have not excluded any responses or individual data points from our analysis. Where we did notice outliers, for example the 10 year expected investment period discussed in Section 3.5.5, these were explained by the respondent. The range that may need to be considered with caution is hurdle rates. Of the 29 respondents for onshore wind, only 6 chose to provide hurdle rates and these were not consistent across responses, ranging from a low of 10% to a high of 15%. Due to the lack of clarity of the basis of hurdle rates submitted (pre/post tax, real / nominal, as discussed in Section 3.5.5), we are of the opinion that these values are not robust for the purposes of modelling levelised costs and other sources should be sought.

A number of respondents have mentioned the impact of PPA discounts on their costs. It is clear from the amount PPAs are discussed (see the qualitative section for further discussion) that PPA discounts are a key concern for respondents regarding the setting of the strike price.

Although the data is sometimes different from ROBR numbers (especially pre-development costs), we are confident that the data quality is reasonably high relative to other technologies covered in the CfE and the numbers provided here are those intended by the respondents. We believe that the data gathered from the CfE for Onshore wind could be used to guide the derivation of levelised costs, but that other sources should be sought, especially for hurdle rates.

3.6. Offshore wind A

There were 7 responses for offshore wind A. This includes all offshore wind not self-selecting as “deep or far offshore”. Respondents did not explicitly state which vintage of project they were referring to, Round 2 (R2) or Round 3 (R3). However, we believe that there is a mixture of R2 and R3 projects included in offshore wind A responses, and a number of the R2 projects may be extensions (Round 2.5 projects) which may share some of the characteristics of the lower cost R3 project. There were originally 8 responses to offshore wind A. However, we chose to exclude 1 response from the dataset as the information provided in it was identical to another response and came from the same respondent.

There was a large range in plant capacity for offshore wind A, with a minimum of 250 MW and a maximum size of 900 MW. The mean plant size was 525 MW. Table 6 summarises the offshore wind A data and compares the results to the ROBR median for both R2 and R3. The full data summary, for all technologies, can be found in Annex A. The derivation of the Crown Estate data is explained in Annex B.

Table 6 - Offshore wind A summary statistics

		CfE				ROBR (R2)			ROBR (R3)			Crown Estate (A&B)
		Mean	**L**	**M**	**H**	**L**	**M**	**H**	**L**	**M**	**H**	**M**
No. CfE Responses	-	*7*										
Pre-development costs	£/kW	110	70	100	161	46	70	120	49	100	150	150
Pre-development period	Years	6	4	5	10							
Construction costs	£/kW	2990	2689	3046	3226	2000	2300	2700	2500	2900	3500	2508
Construction period	Years	4	3	3	5		3			3		
Total opex	£/kW/year	153	103	143	225		126			165		157
of which VOM	*£/MWh*	*6.8*	*1.8*	*5.2*	*13.3*		*1.5*					
Operational lifetime	Years	22	20	20	25		23			22		
Expected investment period	Years	22	20	22	25							
Availability	%	94%	92%	94%	95%		94%			95%		
Load factor (Net of Availability)	%	43%	39%	44%	47%		38%			40%		43%
Plant Capacity	MW	563	275	588	825							
Hurdle Rate (Pre tax real)	%											

3.6.1. Pre-development costs

For offshore wind A, pre-development costs ranged from a low of 70 £/kW to a high of 161 £/kW, across the 7 responses. The median value of 100 £/kW is higher than the R2 median from the ROBR of 70 £/kW and the same as the R3 median of 100 £/kW (R3). The ROBR does provide a large range for pre-development costs and the CfE offshore wind A median is below the high value from the ROBR R2. Given the possible mix of projects in offshore wind A (R2, R2.5, R3) we believe the range of results is consistent with the ROBR. The Crown Estate pre-development costs were greater than both the CfE and ROBR, at 150 £/kW/year[10].

The submissions for pre-development costs were of good quality and it appears that there is a genuinely large range in these costs. A number of respondents commented that technical costs were high due to the bespoke analysis required at each project site – the bespoke nature of this analysis will also add uncertainty to these costs. Technical costs (where presented separately) were similar in magnitude but slightly larger than planning costs. The breakdown for ROBR pre-

[10] Our understanding is that The Crown Estate pre-development cost includes all costs to the point of FID, and is inflated to equate to an 'overnight' at point of FID, reflecting a developer return of around 20-25%. We therefore expect this value to be higher than the ROBR and CfE values which do not inflate this cost.

development costs was not available, so it is not clear if respondents to the CfE expect technical costs or planning costs to be greater, relative to ROBR R2.

There is a large range in the pre-development period for offshore wind A, with a low value of 4 years, median of 5 and high of 10. Six of the eight respondents for offshore wind A provided a pre-development period and of these four answered between 4 and 5 years. The remaining respondents answered 8 and 12 years so were significantly higher than the other responses. These may show the high value as artificially high, considering that most respondents answered lower than half of this. Having looked carefully at the response where 12 years was submitted, we are satisfied that this is the correct value that the respondent intended. It may reflect the actual time elapsed since project conception, noting that Round 2 sites were awarded in 2003.

3.6.2. Construction costs

Construction costs ranged from a low of 2689 £/kW to a high of 3226 £/kW, with a median of 3046 £/kW, from 6 responses. The median is significantly higher than the ROBR median of 2300 £/kW for R2 and 2900 £/kW for R3 projects. Many respondents stated that the ROBR figures were too low for construction and have become out of date. It was noted that R2 / 2.5 projects commissioning in 2016/17 would be similar to R3 projects in terms of site, and would have similar construction costs. The CfE responses for offshore wind A likely contain a mix of late R2 and early R3 projects, and have a median construction cost of 3046 £/kW, close to the ROBR R3 figure of 2900 £/kW and within the range for R3, with the high value at 3500 £/kW. This is much higher than the Crown Estate construction costs of 2508 £/kW. The CfE data is of sufficient quality for us to state that respondents believe costs have increased, though with only 7 responses it may be prudent to seek other sources.

We note that construction costs for the offshore connection have been removed from total construction costs, as these upfront costs will be recouped through transfer of the asset to an OFTO. The costs of the OFTO asset have been included in operational costs instead because they will be paid annually via TNUoS.

Construction period was found to have a low and a median of 3 years, with a high of 5 years. This is the same as the 3 year construction period assumed in the ROBR. Although there was 1 unexpectedly high response (7 years), all of the other respondents ranged from 2 to 3.5 years. We could not find any reason to suggest this is not the value intended by the respondent. It is possible that this could correspond to the total period for different phases of construction in a single zone.

3.6.3. Operational costs

Total opex costs ranged from a low of 103 £/kW/year to a high of 225 £/kW/year. The CfE median of 143 £/kW/year falls in between the ROBR R2 median figure of 126 £/kW/year and the ROBR R3 median of 165 £/kW/year. This is to be expected given that offshore wind A contains a mixture of both R2 and R3 projects. Some respondents stated that the ROBR numbers were broadly correct for operational costs, though highlighted that these could be highly variable dependent on the particular site. TNUoS will vary by site (both the OFTO element and the onshore wider element) and therefore a large range in these values is reasonable.

VOM costs, when given separately to total opex were more widely distributed, ranging from £1.8/MWh to £13.3/MWh, and with a median of £5.2/MWh. This is significantly above the ROBR

R2 median of £1.5/MWh. For R3 VOM was not presented separately and these costs will be included in fixed, meaning it is not possible to compare VOM to the CfE. No explanations were provided for the large VOM estimates. It is plausible that respondents have chosen to split costs differently between fixed and variable costs.

3.6.4. Technical assumptions

The median load factor for offshore wind A was 44%, higher than the ROBR median values of 38% and 40% for R2 and R3 projects respectively. Respondents did not provide any commentary suggesting a recent increase in load factor expectations compared to the ROBR. Although most of the load factor data clustered around the mean, the six responses ranged from a low of 39% to a high of 47%.

There is a small range of values for operational lifetime, from 20 to 25 years, with a median of 20. This is lower than the ROBR R2 figure of 23 years for R2/2.5. Most respondents made a binary choice between 20 and 25 years, and in this case the majority favoured 20 years.

3.6.5. Financial assumptions

As seen with onshore wind, there was a 5 year range for expected investment period for offshore wind A, from a minimum of 20 years, to a maximum of 25, resulting in a median of 22 years from 4 responses. Where this value was given, it matched the operational life.

An additional 2 responses were received stating an investment period of 3 years. We chose to exclude 2 of the responses to the expected investment period question. This is because respondents, giving 3 years for expected investment, had most likely misinterpreted the question as referring to the period over which capital is invested. We are confident that this was a mistake from the respondents and they did not intend to state an expected economic lifetime of 3 years.

No respondents submitted hurdle rates for offshore wind A projects.

3.6.6. Summary

Offshore wind A had 7 responses. Although there is a large range in some of the summary statistics (pre-development costs), the responses were clear and complete. The large range appears to be due to variations between projects as the costs did not cluster around the means, and were spread fairly evenly amongst the range. The range of projects could reflect the diversity of projects in the UK, for example with capacity ranges from 250 MW to 900 MW, and a range of depths and distances to shore.

It is important to note again that the CfE categories of offshore wind A and offshore wind B do not map exactly onto R2 and R3 projects. Where sometimes offshore wind A seems quite different to ROBR R2, the results are actually very similar to ROBR R3. Although the data does not fall neatly into the same categories as R2 and R3 in the ROBR, it is within the range of both so is likely representative of offshore wind A responses which come from a mixture of R2 and R3 projects. The responses are also similar to the Crown Estate data (with the exception of construction costs), which tends to fall between R2 and R3 medians from the ROBR. We believe that the CfE figures presented here are as intended by respondents, and could be used in conjunction with other sources when deriving levelised cost estimates, noting the difficulties in combining data sets due to the Offshore wind A/B vs. R2/R3 category mapping.

3.7. Offshore wind B

There were 7 responses for offshore wind B. Respondents submitted cost estimates using Annex B of the CfE template, which contained slightly different questions to Annex A cont'd used by other technologies. The mean plant capacity for offshore wind B was 992 MW, with a range from a minimum of 500 MW to a maximum of 1500 MW. Table 7 summarises the offshore wind B data and compares the results to the ROBR R3 median and Crown Estate mean. We have assumed that all or almost all of the responses correspond to R3 projects, although this is not stated in responses. The full data summary, for all technologies, can be found in Annex A. The derivation of the Crown Estate data is explained in Annex B.

Table 7 - Offshore wind B summary statistics

		CfE				ROBR (R3)			Crown Estate (C&D)
		Mean	**L**	**M**	**H**	**L**	**M**	**H**	**M**
No. CfE Responses	-	*7*							
Pre-development costs	£/kW	122	54	120	182	49	100	150	150
Pre-development period*	Years								
Construction costs	£/kW	3378	2932	3258	3969	2500	2900	3500	2687
Construction period*	Years						3		
Total opex	£/kW/year	232	170	206	316		165		198
of which VOM	*£/MWh*	*1.8*	*1.4*	*1.8*	*2.2*				
Operational lifetime	Years	23	20	24	25		22		
Expected investment period	Years	23	21	24	25				
Availability	%	94%	94%	95%	95%		95%		
Load factor (Net of Availability)	%	44%	42%	44%	48%		40%		47%
Plant Capacity	MW	992	625	1000	1350				
Hurdle Rate (Pre tax real)	%								

*Annex B did not ask respondents to provide pre-development and construction periods.

3.7.1. Pre-development costs

Offshore wind B pre-development costs range from a low of 54 £/kW to a high of 182 £/kW. The median for pre-development costs is 120 £/kW, in between the ROBR R3 median of 100 £/kW and Crown Estate estimate of 150 £/kW. Some respondents highlighted the potentially large range in pre-development costs due to the variation of offshore sites, and this range is seen in the cost estimates submitted.

Annex B did not ask for pre-development period duration, so it is not possible to assess this using CfE data.

3.7.2. Construction costs

The CfE offshore wind B median for construction costs is 3258 £/kW. This is higher than the ROBR median of 2900 £/kW and the Crown Estate mean of 2687 £/kW. Offshore wind respondents stated that the ROBR figures were too low for construction and have become out of date. The low value for construction costs stated in the CfE is 2932 £/kW and the high value is 3669 £/kW, showing a large range. This category covers both deep and far from shore projects. Deep projects are likely to have higher foundation costs contributing to the construction costs, whereas for far from shore this cost element may be more similar to offshore wind A. The respondents with the highest and lowest construction costs were the same as those with the highest and lowest pre-development costs and may reflect the physical variation in deep offshore sites. Some respondents stated that these costs were very uncertain and would not be known until a full geological inspection had been carried out. In our view there is a higher level of overall uncertainty than for offshore wind A for example, as a result of the likely earlier stage of development and more challenging nature of these projects.

In Annex B, the format of construction cost data requested was different to Annex A cont'd and respondents have often provided turbine costs separately from other construction costs. Where this was the case (6 responses) the turbine costs ranged from 1119 £/kW to 2082 £/kW, with a mean of 1546 £/kW. Costs excluding turbine costs ranged from 1600 £/kW to 2530 £/kW, with a mean of 1913 £/kW. Most of the respondents have not yet selected a turbine manufacturer/model, which introduces an inherent uncertainty into the turbine costs stated.

Annex B did not ask for construction period duration, so it is not possible to assess this using CfE data.

OFTO construction costs have been excluded from total construction costs for offshore wind B, and respondents were asked to submit these costs separately. The OFTO construction costs ranged from 514 £/kW to 1101 £/kW with a mean of 905 £/kW. These costs are captured in total opex rather than construction costs because these will be paid on an annual basis via TNUoS.

3.7.3. Operational costs

The total opex median was 206 £/kW/year, with a range from 170 £/kW/year to 316 £/kW/year. This is higher than the ROBR median of 165 £/kW/year and similar to the Crown Estate estimate of 198 £/kW/year.

A number of respondents stated that expected OFTO charges were likely to be high due to the lack of industrial experience in laying deep offshore cables. The current lack of supply in trained maintenance crews was also highlighted as a risk that may push up operational costs.

The median VOM for offshore wind B from the CfE was 1.8 £/MWh with a low of 1.4 £/MWh and high of 2.2 £/MWh. There were only 2 responses to this question: 1 stated VOM to be 1.3 £/MWh and 1 stated VOM to be 2.3 £/MWh. This cost was not included in either the ROBR or Crown Estate data. We note that VOM for offshore wind B was lower than the VOM for onshore wind.

This may be a result of different allocations of costs between fixed and variable elements; in general the total opex is more robust than the cost breakdown.

3.7.4. Technical assumptions

The median load factor of 44% falls in between the ROBR R3 median of 40% and Crown Estate mean at 47%. The low value is 42% and high value of 48%. Respondents expressed uncertainty about these load factors, stating firstly that they are very site specific and secondly that these will be heavily influenced by turbine power curves which are not always available.

Water depths ranged from 45-70m, with a mean of 51m, and sites situated between 15km and 57km offshore, with a mean of 37km. The distance to the proposed grid connection point varied from 35km to 130km, with a mean of 85km. No respondents submitted which turbine manufacturer and model would be used, many stating that this was not known. This highlights the uncertainty surrounding these projects at this time.

The operational lifetime for offshore wind B plant, as with the other wind lifetimes, ranged from 20 to 25 years, producing a mean of 23 years. This was similar to the ROBR median of 22 years, though is higher than the CfE median for offshore wind A (20 years). We do not believe this difference is significant, as almost all offshore wind (A & B) respondents submitted a generic value of 20 or 25 years. The differences in operational lifetime between offshore wind A and B are discussed in further detail in Section 3.7.7.

3.7.5. Financial assumptions

The expected investment period for offshore wind B ranged from 20 to 25 years, with a median of 24 years. An additional 2 responses were received that submitted values of 5 and 8 years respectively. It was assumed that in these cases the respondents had misinterpreted the question, and the responses were excluded from the summary statistics.

None of the respondents provided hurdle rates for offshore wind.

3.7.6. Summary

Offshore wind B had 7 responses. There is a large range in some of the summary statistics (especially for pre-development costs and opex). However, the responses were clear and complete. The large range appears to be due to variations between projects as the costs did not cluster around the medians, and were spread amongst the range. A major theme of these responses was the uncertainty in costs stated by respondents, due to many of these projects being at earlier stages in the development cycle.

As already discussed with offshore wind A, it is important to highlight that the CfE categories, of offshore wind A and offshore wind B, do not map exactly onto R2 and R3 projects. Despite this, the offshore wind B projects would all certainly fall under the R3 ROBR category. We are therefore confident that R3 is the correct ROBR technology category to benchmark the CfE results against.

All of the CfE onshore wind B costs were greater than the ROBR R3. Compared to the Crown Estate data, construction costs were higher for both the CfE and ROBR, although lower for pre-development..

The major difference to the ROBR and Crown Estate benchmarks is the higher construction cost. Load factors are also significantly higher than the ROBR data. We are confident that numbers provided are those intended by the respondents with regards to costs. The 7 responses received represent a reasonably large proportion of potential R3 offshore projects in development. However there is a generally high level of uncertainty in costs and specifics of projects that must be borne in mind (see Section 3.7.4). Therefore, for offshore wind B, there is a need to proceed with caution in using this dataset to model levelised costs for the purpose of setting strike prices.

3.7.7. Comparison between offshore wind A and offshore wind B

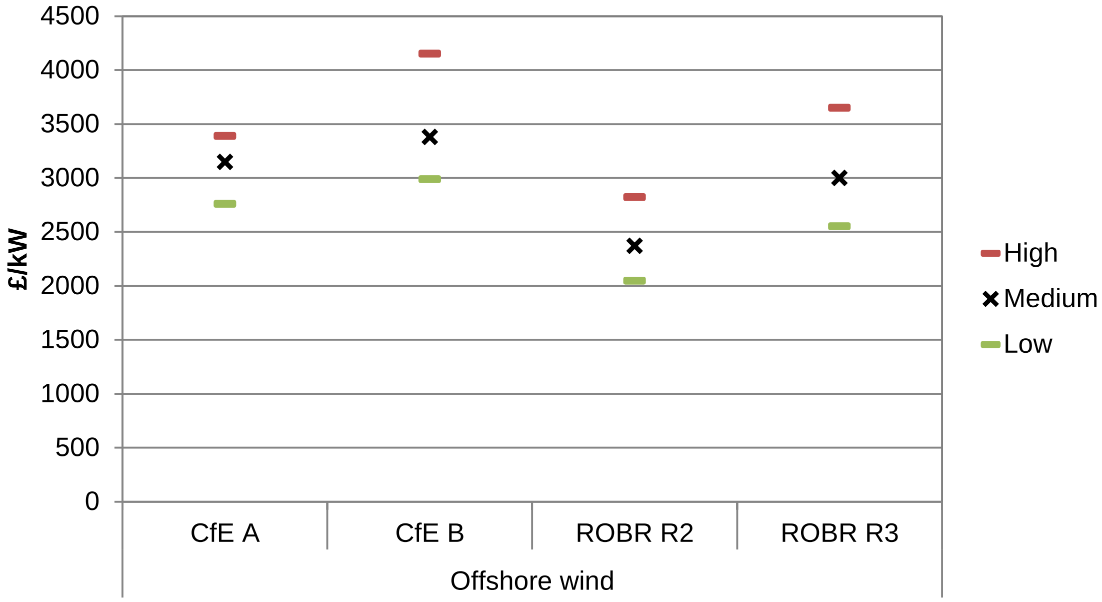
We have added together pre-development and construction costs from the CfE and ROBR for offshore wind, in order to compare the data produced. These can be seen in Figure 4.

It is informative to compare both offshore wind A and offshore wind B with R2 and R3 categories from the ROBR, with the caveat that this is not an exact a comparison as we have already noted that the CfE categorisations do not map neatly onto ROBR R2 and R3. Therefore it may be more appropriate to compare to the R3 costs rather than R2 costs.

Offshore wind A likely contains both R2 and R3 projects. All of the offshore wind A costs fall within the range for ROBR R2 and there is a slight overlap between the lower costs in offshore wind A and higher costs in ROBR R2. Offshore wind A has a small range compared to the other offshore wind data, suggesting that projects are similar to one another.

Offshore wind B costs had a greater range than offshore wind A costs and, although the median for offshore wind B is only slightly higher than offshore wind A, the high values are significantly higher. The offshore wind B costs are also a lot higher than the R3 ROBR data and there is no overlap at all with R2. This suggests that any issues in mapping offshore wind A and offshore wind B onto R2 and R3 categories does not account for the differences seen between the CfE results and the ROBR. This should be viewed in the context of the generally high level of uncertainty in costs and specifics of projects for offshore wind (see Section 3.7.4).

Figure 4 - Comparison of wind pre-development and construction costs



Operational Lifetime

The operational lifetime of offshore wind A is, counter-intuitively, slightly shorter than the operational lifetime for offshore wind B. We believe that this is not significant because most respondents made a binary choice between 20 and 25 years, and there were relatively few responses.

In total, the responses represent close to 10GW of offshore wind capacity. This is likely to be a large proportion of the offshore wind projects that could be developed under the first years of CfDs. This high response rate lends some weight to the data. However, there is significant uncertainty stated by respondents which means that this data should be used with caution when estimating levelised costs.

3.8. Tidal stream

There were 4 responses for tidal stream. This low number was to be expected due to tidal stream being an early stage technology, and there being a limited number of developers of tidal stream. It has not been possible to classify whether responses received were shallow (<40m) or deep (>40m). ROBR costs for both categories are shown for comparison in Table 8. The data is likely to reflect shallow rather than deep projects as these are likely to deploy before deep water projects. The mean plant capacity for tidal stream is 18 MW with a range between 10 MW and 30 MW. These projects' sizes are consistent with the first pre-commercial arrays, and respondents expect costs to reduce in future with learning and economies of scale. Table 8 summarises the tidal stream data and compares the results to the ROBR median. The full data summary, for all technologies, can be found in Annex A.

Table 8 - Tidal stream summary data

		CfE				ROBR - Shallow			ROBR - Deep		
		Mean	**L**	**M**	**H**	**L**	**M**	**H**	**L**	**M**	**H**
No. CfE Responses	-	*4*									
Pre-development costs	£/kW	215	122	170	344		330		390	510	620
Pre-development period	Years	4	3	4	5						
Construction costs	£/kW	5340	4174	5536	6350		3700		4200	4800	5500
Construction period	Years	2	2	2	2		3			2	
Total opex	£/kW/year	433	146	248	867		237			214	
of which VOM	*£/MWh*	*89.7*	*89.7*	*89.7*	*89.7*						
Operational lifetime	Years	23	20	23	25		20			20	
Expected investment period	Years	22	20	20	24						
Availability	%	91%	85%	95%	96%						
Load factor (Net of Availability)	%	31%	28%	31%	35%		40%			40%	
Plant Capacity	MW	18	10	15	27						
Hurdle Rate (Pre tax real)	%	12%	12%	12%	12%						

3.8.1. Pre-development costs

Pre-development costs for tidal stream ranged from a low value of 122 £/kW to a high value of 344 £/kW, with a median of 170 £/kW. This is significantly lower than the ROBR median for tidal stream deep of 510 £/kW. It is not clear why the CfE responses were so much lower than the ROBR. It may be due to a problem in defining the type of tidal stream, although it should be noted that shallow tidal stream also had much greater pre-development costs in the ROBR (330 £/kW). A number of respondents stated that while the ROBR figures are currently the best available data on tidal generation costs, they referred to projects commissioning in 2016, and that, assuming projects have been deployed to drive some learning, after this costs were expected to reduce for tidal technologies. Tidal stream technology is still at an early stage of development so estimated costs will be more uncertain and variable.

Pre-development period estimates ranged from 3 to 5 years, with a median of 4 years.

3.8.2. Construction costs

Tidal stream construction costs ranged from a low value of 4174 £/kW to a high value of 6350 £/kW. The median of 5536 £/kW is significantly above even the ROBR median of 4800 £/kW for deep tidal technology. The range of responses does overlap with the ROBR range. The comments provided with the responses suggest that the ROBR construction cost data “retains some validity” or are “broadly applicable” and no reasons for differences on this cost element are identified.

Respondents did not separate construction costs into constituent parts, though it was noted that there was significant variation in construction costs dependent on location. The most expensive cost estimate was for a project situated in Scotland. The other tidal projects stated their regions as either GB or UK, although it is likely that most if not all of the projects are planned for in Scotland as tidal technology is condensed in this region.

The median construction period was 2 years with all respondents submitting a value. This is the same as the ROBR median. As respondents were clear and did not require interpretation, we suspect differences in construction costs when compared with the ROBR are due to uncertainty in predicting costs for such a new technology.

3.8.3. Operational costs

The median total opex from the CfE was 248 £/kW/year. This was very similar to the ROBR median of 214 £/kW/year. There is a large range in responses with a low value of 146 £/kW/year and a high value of 867 £/kW/year. There is not enough detail within the tidal stream submissions to give further explanation as to why operational costs are spread across such a range.

Only 1 respondent submitted VOM separated from other opex, of 90 £/MWh. This is unexpectedly high for VOM costs and as a result we expect there may be definitional differences between fixed and variable, with this respondent including some costs that would normally be viewed as fixed in their VOM costs. We were not able to ascertain why the value provided is so high.

3.8.4. Technical assumptions

The median load factor is 31%, ranging from 28% to 35%. This is much lower than the median ROBR load factor, of 40% for tidal stream projects. Respondents stated that while they broadly agreed with ROBR costs, the ROBR load factor was far too high, and this point had been recognised by the Government when increasing the ROC bands for tidal technologies, following consultation on the ROBR.

The operational lifetime for tidal stream ranged from 20 to 25 years, with the CfE mean being 23 years, slightly above the ROBR median of 20 years.

3.8.5. Financial assumptions

Only 1 of the tidal stream respondents provided a hurdle rate, answering 12%. The expected investment period ranged from 20 to 25, with a median expected investment of 20 years. As with the expected investment in the previous technologies, respondents tended to answer either 20 or 25 years. In this case, only 3 respondents answered, with 2 providing an expected investment of 20 years, and 1 providing 25.

3.8.6. Summary

The values expressed in this section are based on 4 responses, meaning that individual values have a large impact on the reported results. As discussed in the opening to tidal stream, it is a new technology, with a limited number of developers so needs to be viewed with a degree of uncertainty. We did not exclude any responses or data points. There were some large ranges in values provided by respondents, especially with opex. In addition, some of the data points were very different from the ROBR median (pre-development costs and opex).

As there were only 4 respondents for tidal – and fewer responding to particular questions (e.g. only 1 response for VOM) – it is difficult to draw strong conclusions about this technology from the CfE. Although this could be viewed as a good sample given the small number of projects at the development stage, the variation in the data provided suggests uncertainty about costs (and perhaps a range of different technological solutions) and how they may change in the future. The cost data presented here are a useful guide but should be only one factor in any consideration of costs and should be given limited weight alongside other sources.

3.9. Wave

There were 4 responses for wave. The plant capacity for wave responses ranged from 10 MW to 30 MW with a mean of 18 MW. As with tidal stream, this low number was to be expected due to wave being an early stage technology, and there being a limited number of developers, with a number of markedly different designs for Wave Energy Converters.

Table 9 summarises the wave data and compares the results to the ROBR median. The full data summary, for all technologies, can be found in Annex A.

Table 9 - Wave summary data

		CfE				ROBR		
		Mean	**L**	**M**	**H**	**L**	**M**	**H**
No. CfE Responses	-	*4*						
Pre-development costs	£/kW	112	99	111	127	280	330	380
Pre-development period	Years	4	2	4	5			
Construction costs	£/kW	7723	6790	7971	8457	3600	4400	5200
Construction period	Years	2		2			2	
Total opex	£/kW/year	219	127	229	301		249	
of which VOM	*£/MWh*	*10.0*		*10.0*				
Operational lifetime	Years	21	20	20	24		20	
Expected investment period	Years	21	20	20	24			
Availability	%	90%	83%	91%	96%			
Load factor (Net of Availability)	%	30%	28%	31%	32%		30%	
Plant Capacity	MW	18	10	15	27			
Hurdle Rate (Pre-tax real)	%	11%	10%	11%	12%			

3.9.1. Pre-development costs

Wave pre-development costs ranged from a low value of 99 £/kW to a high of 127 £/kW with a median of 111 £/kW. This is much lower than the ROBR median of 330 £/kW. Despite this difference, most respondents stated that the ROBR figures were ‘broadly correct’, and explained cost differences through ‘true costs’ being very dependent on location and remaining open to large uncertainty. There was no consistent split in costs between technical development and planning. This is likely to be because the industry is still immature relative to other technologies covered in this report and respondents do not yet have an accurate view on what costs will be.

The pre-development period for wave ranged from 2 to 5 years with a median of 4 years.

3.9.2. Construction costs

Construction costs for wave had a median of 7971 £/kW, ranging from a low of 6790 £/kW to a high of 8457 £/kW. All respondents stated construction costs significantly above the ROBR median of 4400 £/kW. One respondent stated that it believed early projects commissioning in 2017 would be up to 10 MW in size, and stated that small test projects such as these would be much more expensive than later, larger projects. Costs were expected to come down once the technology was more mature and being manufactured in higher volumes.

The estimated construction period was 2 years for all responses to the CfE and is the same as the median in the ROBR.

3.9.3. Operational costs

Total opex cost submissions for wave ranged from a low value of 127 £/kW/year to a high value of 301 £/kW/year, with a median of 229 £/kW/year. This is similar to the ROBR median of 249 £/kW/year. It was commented that there are currently only a handful of suppliers of wave technology and maintenance services, and that operational costs were likely to fall as more suppliers enter the market. It is the case that at the moment there is a range of quite different technologies. It is quite likely that this will consolidate before large scale commercial deployment happens. At this stage, wave projects may take a more consistent form with one another and we would expect to see less of a range in the different costs of projects.

Only 1 wave respondent provided a VOM, giving 10 £/MWh. There was no data from the ROBR to compare this to.

3.9.4. Technical assumptions

The median load factor is 31%, ranging from a low of 28% to a high of 32%. The CfE median is consistent with the ROBR median of 30%.

Estimated operational lifetime for wave generators varied from 20 to 25 years, with a median of 20 years. Of the 4 responses to this question, all were binary, with 3 answering 20 years and 1 answering 25. The 20 year median is the same as the ROBR median.

3.9.5. Financial assumptions

The expected investment period for wave respondents ranged from 20 to 25 years, with a median of 20 years. As with operational lifetime, 3 respondents answered 20 years and 1 answered 25. 2 respondents provided hurdle rates, with a median of 11%.

3.9.6. Summary

The values expressed in this section are based on 4 responses, meaning that individual values have a large impact on the reported results. The responses were clear and included the same elements. We can therefore be confident that the values are those intended by respondents, although they are spread across a large range and differ a lot from the ROBR median in some cases (pre-development and construction costs in particular).The relatively early stage of development of wave technology, along with a range in the designs of Wave Energy Converters indicates that these costs are inherently more uncertain that for more mature technologies. We did not exclude any responses or data points. Although there were some large ranges in values provided by respondents (especially in opex and construction costs), respondents commented on how much costs can vary as a result of the project location.

Although 4 responses could be viewed as a good sample given the small number of projects at the development stage, the data provided covered a very large range (for reasons discussed above). The data points presented here should be only one factor in any consideration of costs and should be given limited weight alongside other sources.

4. ASSESSMENT OF TRENDS IN FUTURE COSTS & COST DRIVERS

In Annex A cont'd and Annex B, there were qualitative questions on trends in future costs, and drivers for costs changes. These form a useful part of CfE analysis through explaining further the answers provided in the quantitative section, alongside providing information that could be useful when added into the qualitative analysis. All CfE technologies were asked questions on the following costs: capital, operational and pre-development. In addition, offshore wind B was asked to provide information on trends for balance of plant and installation costs. The responses are considered in detail below. In this section we have included responses from all technologies, included those from technologies with 3 or fewer responses.

4.1. Capital costs

There were two questions relating to capital costs:

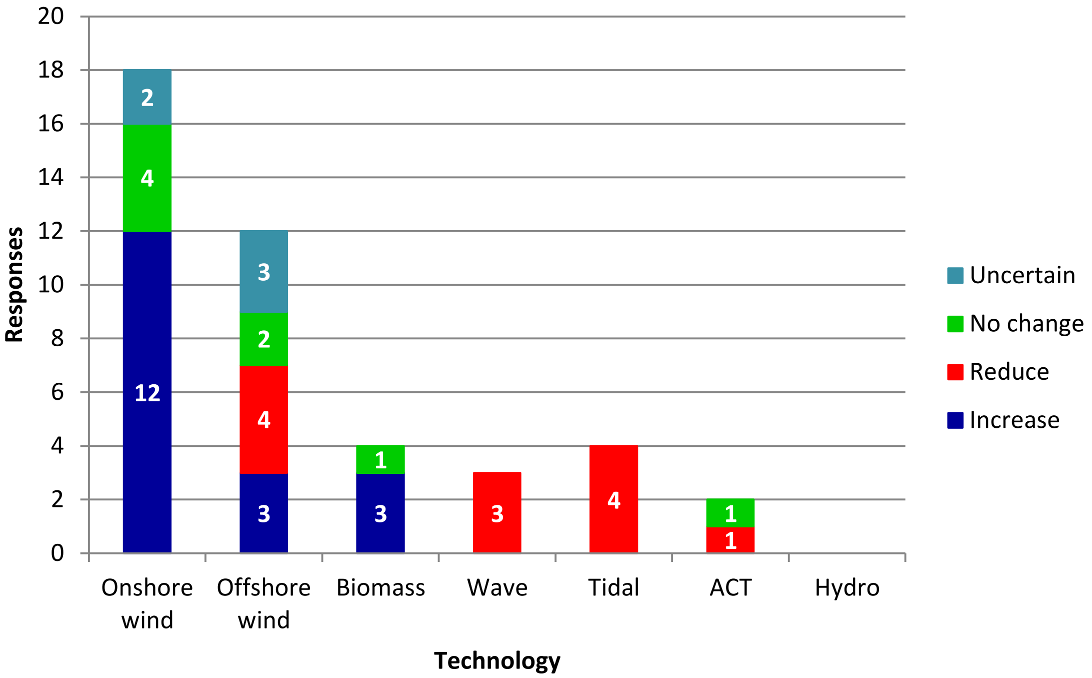
- *"How do you think capital costs are likely to change over the next 5, 10, 15 years?"*
- *"What do you consider to be the key cost drivers behind capital/ construction costs? (e.g. steel, exchange rates, energy costs, labour costs, other)"*

These two questions have been considered separately and are described below.

4.1.1. Changes to capital costs

Of the 59 quantitative responses, 43 responded to the question of how capital costs are likely to change over the next 5, 10, 15 years. These came from a range of different technologies. The breakdown of the responses by technology can be seen in Figure 5.

Figure 5 - Changes to capital costs



Of the 18 onshore wind respondents, the majority (12) believed that capital costs would increase. Four respondents believed that capital costs will reduce and one respondent was uncertain. The 12 offshore wind respondents were divided: three believed costs would increase, four believed costs would decrease, two did not believe there would be a change to costs, and three were uncertain. For biomass respondents, three stated that costs would increase, and one thought there would be no change.

Clear differences can be seen between these 3 technologies discussed and wave and tidal, for which all respondents believed that capital costs would reduce in the future. This shows that immature technologies are more likely than more mature technologies to experience future cost reductions. One of the 2 ACT respondents also believed that capital costs would reduce, with the other suggesting no change. None of the hydro respondents answered this question.

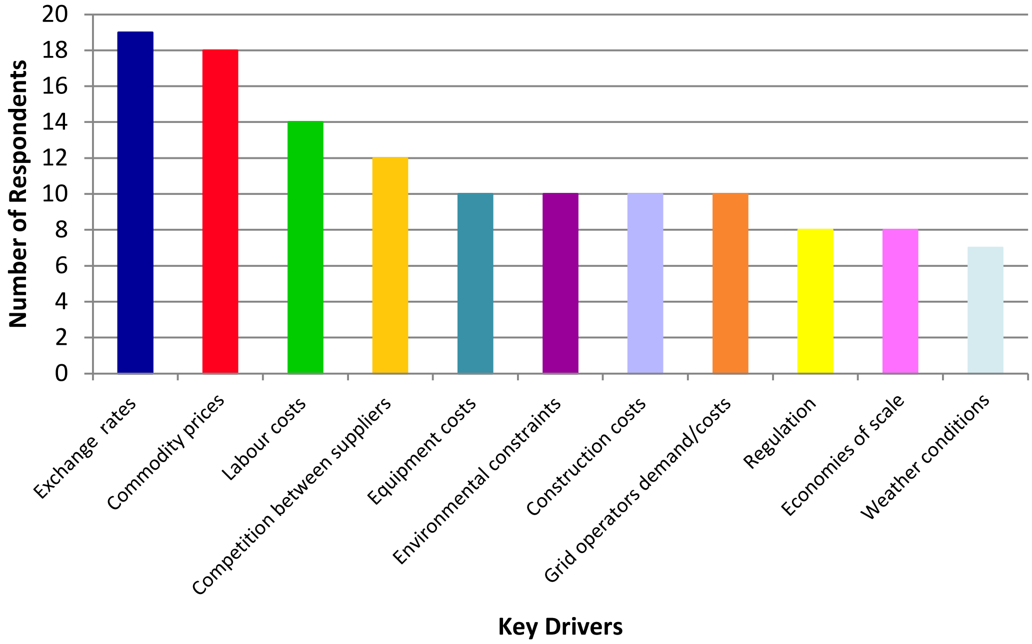
There is a clear technology split with the newer and less developed technology respondents believing costs will reduce. Developers of the more established technologies, such as onshore wind and biomass were more likely to believe costs would increase.

4.1.2. Drivers behind capital/construction costs

In total, 55 respondents answered the question asking about the key cost drivers behind capital/construction cost changes. Again, these answers came from a wide range of technologies.

The drivers behind capital costs mentioned most frequently by respondents are summarised in Figure 6.

Figure 6 - Drivers behind capital costs



The major drivers mentioned above should be considered in the setting of strike prices which will be in place for a number of years. Respondents will be exposed to the impact of variation in exchange rates and commodity prices in the future. It is extremely difficult to predict which way commodity prices and exchange rates will move. In contrast, some of the changes in cost drivers anticipated by respondents are viewed by respondents as more certain: the impact of labour costs, likely to drive costs up due to an insufficiently large trained workforce in the short to medium term.

As with commodity prices and exchange rates, precisely what will happen with competition between suppliers in the future is not clear. If in the future there is an increase in the number of suppliers, leading to more competition, this is expected to drive down capital costs, though the timings are uncertain.

Equipment costs were cited by developers across a range of technologies as an important driver of construction costs. For example, 3 onshore wind respondents highlighted that 65% of total capital costs for onshore wind are turbine costs. This was not restricted to onshore wind, the following technologies also highlighted equipment costs as a key driver: hydro, offshore wind, ACT and wave. Equipment costs themselves could be driven by commodity prices, exchange rates, and competition between manufacturers.

Environmental constraints were mentioned by 8 onshore wind respondents and 2 hydro respondents. Although it was not completely clear what respondents meant when referring to environmental constraints, it is likely that this referred in many cases to the environmental aspects of the planning process. A further 2 respondents (both onshore wind) highlighted planning constraints explicitly as a key driver of future costs.

Construction costs were highlighted by 10 respondents across the different technologies. This driver seems to be a misinterpretation of the question. The question wanted to know what drives construction/capital costs; therefore citing construction costs provides no insight. Grid connection costs were highlighted by 8 respondents as a key driver.

Regulation was mentioned explicitly in this question only by wind respondents, 2 offshore and 6 onshore. However, regulation was referred to in passing in comments received with responses from other technologies, and given the large number of submissions from wind projects it is not thought that this issue affects wind projects proportionally more than other technologies.

The impact of economies of scale was noted as an important driver of construction costs by a number of participants. Responses that provided this driver came from the following technologies: onshore wind, wave and tidal.

Most of the drivers mentioned did not differ between the different technologies and answers were spread between both technology type and region. The only exception to this is weather conditions which were only mentioned by responses that related to wind: 6 onshore and 1 offshore. In our view this is a key driver of project revenues of both onshore and offshore wind, but in terms of impact on construction costs is more likely to impact offshore wind where periods of good weather are required for installation of turbines.

4.2. Operational costs

There were two questions relating to operational costs:

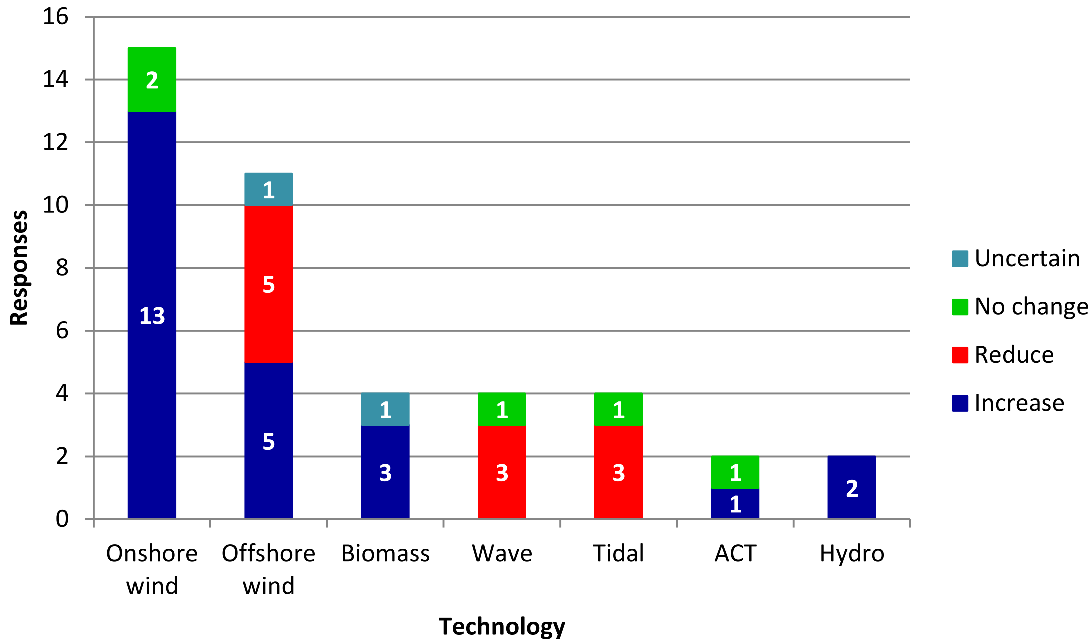
- *"How do you think operational costs are likely to change over the next 5, 10, 15 years?"*
- *"What do you consider to be the key cost drivers behind operational costs? (e.g. exchange rates, fuel costs, labour costs, other)"*

These 2 questions have been considered separately and are detailed below.

4.2.1. Changes to operational costs

There were 42 responses to the question of how operational costs are likely to change over the next 5, 10, 15 years. These came from a range of different technologies. The breakdown of the responses by technology can be seen in Figure 7.

Figure 7 - Changes to operational costs



There were clear differences between the technologies for predicting future changes to operational costs. The majority (13) of the onshore wind respondents believed costs would increase, with two believing there would be no change. Offshore wind responses were divided, with five predicting increases, five predicting reductions, and one uncertain

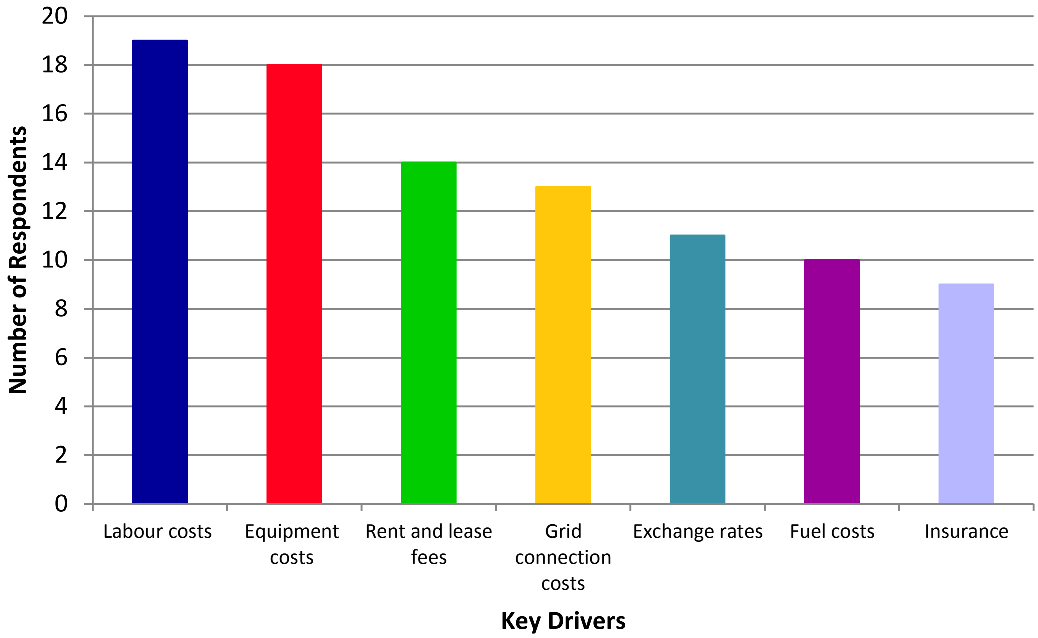
The majority of biomass respondents (3) believed operational costs would increase, with one being uncertain. The two ACT respondents were divided, with one believing costs would increase and one believing there would be no change. Both hydro respondents believed there would be an increase in costs. Wave and tidal respondents had a very different view on how operational costs would change to the other technologies. Both had four respondents with three of each believing operational costs would reduce in the future, and one of each believing there would be no change to operational costs. As with capital costs, this is likely to be because wave and tidal technologies are less developed than some of the other technologies and significant technology learning and supply chain development is anticipated.

4.2.2. Drivers behind operational costs

The second question on key cost drivers behind operational costs was answered by 51 respondents. Again, these were from a range of different technologies.

The drivers behind operational costs that were mentioned most frequently by respondents are summarised in Figure 8.

Figure 8 - Drivers behind operational costs



All of these key drivers were answered by a mixture of different technologies, suggesting that the important drivers behind operational costs are not technology specific.

Labour costs, outlined by 19 respondents, have already been discussed in the quantitative section of this report (see Section 3.5.3). Respondents, from a range of technologies were concerned that a lack of skilled labour is meaning labour costs are high and form a large part of operational costs. One onshore wind respondent stated that labour costs are 70% of the cost drivers for operational costs. Respondents tended to state that labour costs would remain high (rather than rise) for the foreseeable future, until more skilled labour was trained.

The next most mentioned driver, with 18 respondents from a range of technologies, was on-going equipment costs. Equipment costs were mentioned across the range of technologies, with some going into detail as to why they felt this to be a key cost driver. One offshore wind respondent highlighted that ‘turbine technology is moving in a way to reduce O&M costs related to the cost to maintain key turbine components’. Another offshore wind response highlighted that it is ‘maintaining the integrity of the turbines and foundations’ that drives costs.

Rent and lease fees were mentioned by fourteen respondents as a driver of operational costs. However, there was little insight given as to how these are expected to move in future. Grid connection costs, inclusive of TNUoS, were the next most mentioned driver with13 respondents highlighting these. It was seen to be important due to being such a large proportion of operational costs, with one respondent suggesting that “TNUoS makes up lion’s share of O&M costs (c. 47.5%)” for their project.

Exchange rates, listed by 11 respondents, will affect operational costs. As discussed for capital cost drivers it is not clear in which direction exchange rates will move in the future. Future fuel costs, as with commodity prices and capital costs, will be similarly uncertain. These were mentioned by 10 respondents. Of these, 5 were for biomass, which is to be expected as the technology has significant input fuel costs. The remaining 5 responses were for offshore wind projects, and we hypothesise that fuel costs relate to the operational costs of vessels used to construct and maintain the plant. Nine respondents highlighted insurance as a key cost driver.

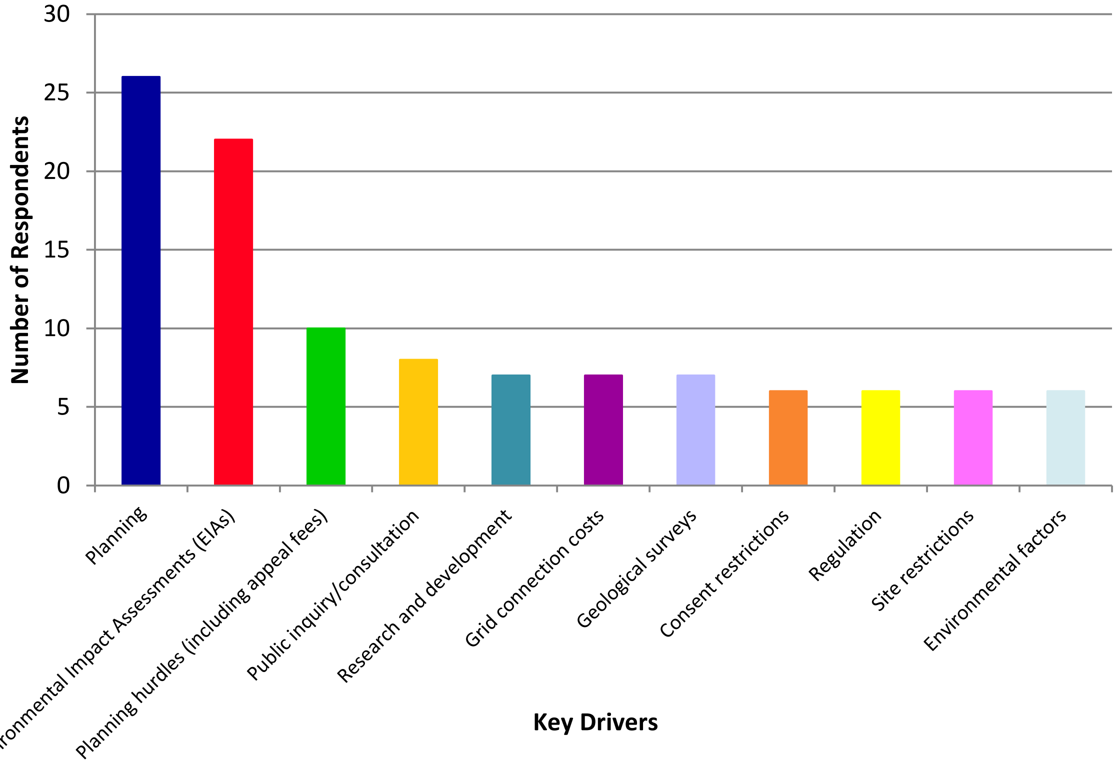
4.3. Pre-development costs

Respondents were asked the following question about pre-development costs:

- *"What do you consider to be the key cost drivers behind pre-development cost?"*

There were 52 responses to this question, from a range of technologies. The drivers behind pre-development costs that were mentioned most frequently by respondents are summarised in Figure 9.

Figure 9 - Drivers of pre-development costs



Planning costs, mentioned by 26 of the 52 respondents, will make up a large proportion of pre-development costs. There is also potential for projects to be held up or fail completely at the planning stage - 10 respondents mentioned 'planning hurdles' as another key cost driver. Environmental Impact Assessments (EIAs) and public enquiry/consultation, mentioned by 22 and 8 respondents respectively, are also significant pre-development costs. These, as well as research and development and geological surveys (both 7 respondents) are part of the pre-development stage of a project. The necessary surveys and research before a project can proceed are technology specific and differences were seen depending on whether technologies were based on land or water. For example, geological surveys were only mentioned by respondents from wave, tidal and offshore wind. In contrast, of the 22 respondents stating EIAs as a key cost driver, 20 were for onshore wind, 1 for biomass and 1 wave.

Whilst most answers were spread between responses for different technologies, there were some technology specific differences: planning hurdles was only suggested by wind respondents; this was predominantly onshore wind, with 9 responses, compared to 1 offshore wind response listing planning hurdles as a key driver. It is widely stated that the planning system poses a difficulty for onshore wind. In addition, 'public inquiry/consultation' was a driver given only by onshore wind respondents.

Site restrictions, consent restrictions and environmental factors (all mentioned by 6 respondents) are site specific factors that can drive pre-development costs.

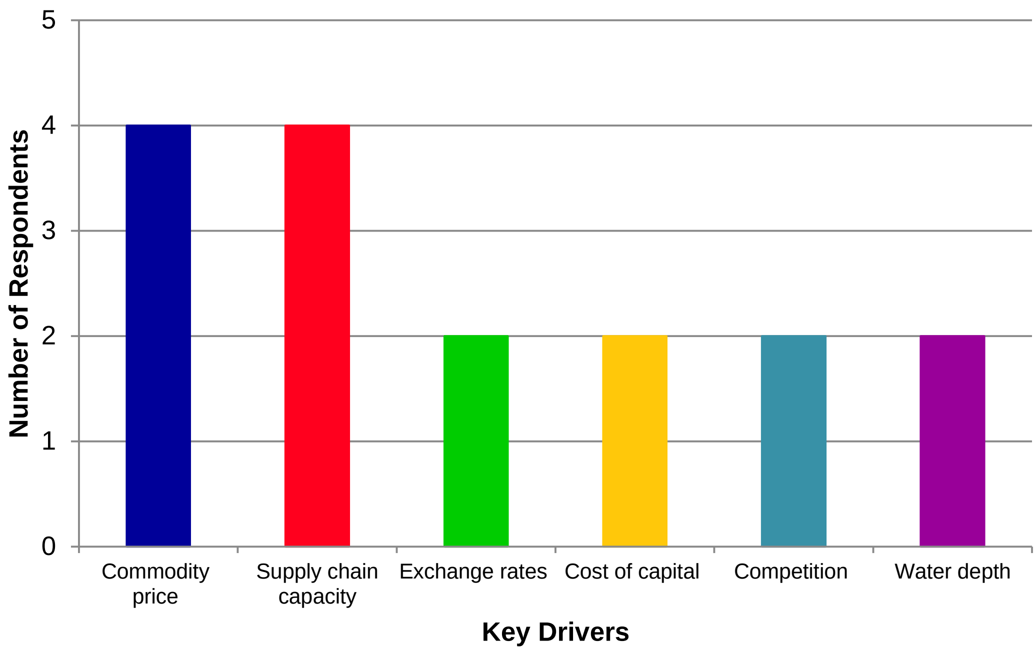
4.4. Balance of Plant and Installation costs

Annex B respondents were asked:

- *"What do you consider to be the key cost drivers behind balance of plant & installations costs? (e.g. steel, exchange rates, energy costs, labour costs, other)"*

This question was asked in Annex B so was only applicable to deep or far offshore wind. Five respondents answered this question. The drivers behind balance of plant and installation costs that were mentioned most frequently by respondents are summarised in Figure 10.

Figure 10 - Drivers of balance of plant and installation costs



The following factors were raised once: availability of HV transmission, foundation supply, installation costs, weather conditions, ground conditions, distance to the shore, infrastructure costs, consent restriction, grid issues and investment environment.

Of the five responses to drivers of balance of plant and installation costs, four believed commodity prices to be a key driver. Exchange rates and cost of capital, both stated by two respondents will pose similar difficulties in the setting of strike prices over a multi-year period.

Supply chain capacity, highlighted by four respondents, and the level of competition, mentioned by two respondents, will also be key drivers. Current lack of supply and associated competition has the effect of holding up prices, though it was suggested this would improve in the future as more suppliers enter the market.

Water depth, highlighted by two respondents, is a site specific driver of balance of plant and installation costs and will vary by individual project.

4.5. Summary

Respondents did not break down their assessment of future costs drivers between the 5, 10 and 15 year periods requested, but we suspect that the focus was more on near term drivers in their responses. Variations in expectations in future cost trajectories were noticeably different between different technologies. Respondents from the more established technologies generally think that costs will increase in the next few years. These views could be a result of the cost increases we have seen over the past few years, with respondents assuming that these will continue. Less mature technologies (for example, wave and tidal) were more likely to believe costs will reduce. This is to be expected as there is greater potential for learning from these technologies over the next few years.

When going through the cost drivers, respondents listed various factors they believed would drive the different cost parameters in the future. Missing from respondents' answers though was further explanation as to exactly how they believed these drivers would shape future costs. This was the case across all of the different cost parameters, although was particularly pronounced for pre-development costs and balance of plant and installation costs.

There was very little differentiation between the different technologies, with the same cost drivers being important across the different projects. This may be because many drivers are external to the technology itself, for example exchange rates or commodity costs. Environmental factors and weather conditions are technology specific as these relate to the actual technology itself in some cases.

5. ASSESSMENT OF QUALITATIVE RESPONSES

5.1. Approach to qualitative responses

Qualitative data was collated from multiple sections of the responses – Annex A, Annex C, comments found in Annexes A cont'd and B, and in any supporting documents or cover letters sent in with the CfE responses. In this section we have included responses from all technologies, included those from technologies with 3 or fewer responses.

A framework was developed for summarising qualitative responses that used the questions asked in the CfE as its basis. All qualitative data submitted to the CfE was used, where relevant to the CfE questions. For each question a number of common answers were developed, and the responses mapped onto these. For example, in answer to the question "are ROBR cost estimates applicable to CfD strike price setting" answers were mapped to: "Yes", "No", "Too High", "Too Low", and "Don't Know". Additional comments giving further explanation were captured and summarised for each question.

Where comments were received that did not refer to specific CfE questions, but were broadly relevant, these were summarised for each response. Where comments were received that were not related to the CfE these were omitted, although a separate list of interesting out of scope responses has been collated for National Grid.

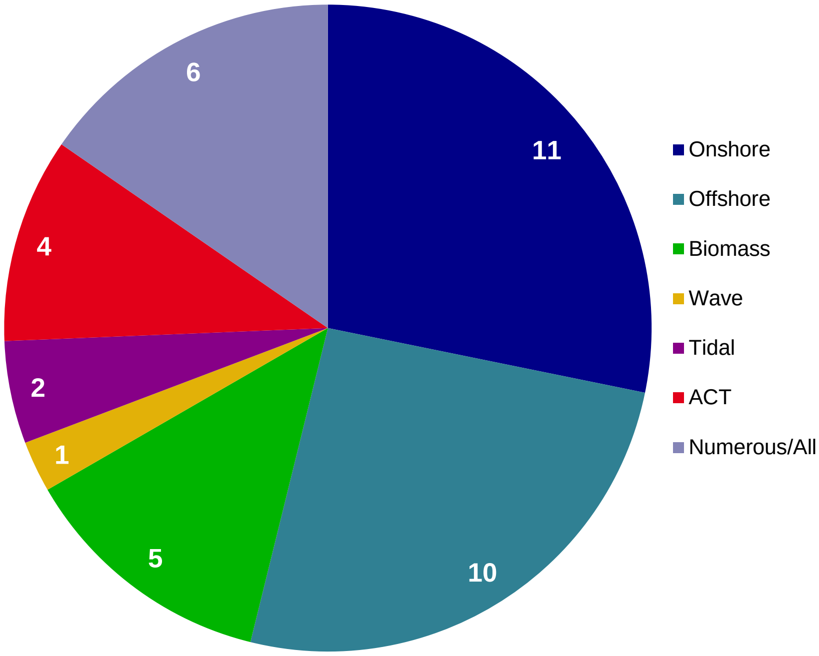
5.2. Overview of responses

There were 39 qualitative responses to the CfE. Of these, 10 submitted qualitative responses only and 29 respondents completed qualitative and quantitative responses. Responses were received from a mixture of parties, including 5 of the six large vertically integrated energy companies, alongside independent and merchant generators.

The format of the responses received was mixed: 13 respondents submitted their responses to Annex A in the Excel template provided and 15 submitted their answers to Annex C in the Excel template. Alongside, and often instead of using the template, many respondents chose to submit pdf or word documents and/or cover letters that summarised their views.

Figure 11 shows the breakdown of the qualitative responses by technology. These categories are broader than those used in the quantitative responses. The qualitative questions are not technology specific, and respondents did not give the precise detail of which technologies they were referring to that would allow responses to be mapped to the same categories as quantitative responses. In some cases the responses covered a number of technologies or referred to all renewable generation technologies in aggregate.

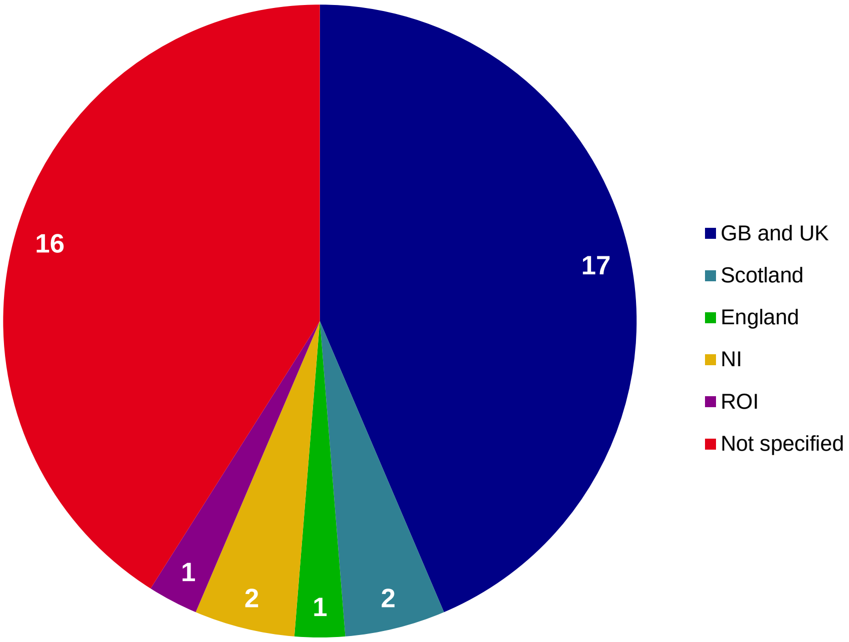
Figure 11 - Qualitative responses by technology



5.3. Breakdown of responses by region

Figure 12 shows the breakdown of qualitative responses by the region they refer to. It can be seen few respondents specified a region, although this information has been captured where it was available. As with quantitative respondents, where a region is not specified, we have categorised this as ‘not specified’. The category ‘UK and GB’ has been used when the response has referred to itself as applicable to these regions.

Figure 12- Qualitative responses by region



*N.B. The response from the Republic of Ireland was not included in our analysis, although some interesting observations have been captured as 'outside the scope of the CfE' and flagged to National Grid

5.4. Responses falling outside the scope of the CfE

As mentioned in the introduction, there were some responses that provided detailed information that did not relate to the CfE, for example because they related to technologies which are not covered. These have been captured in a separate document provided to National Grid.

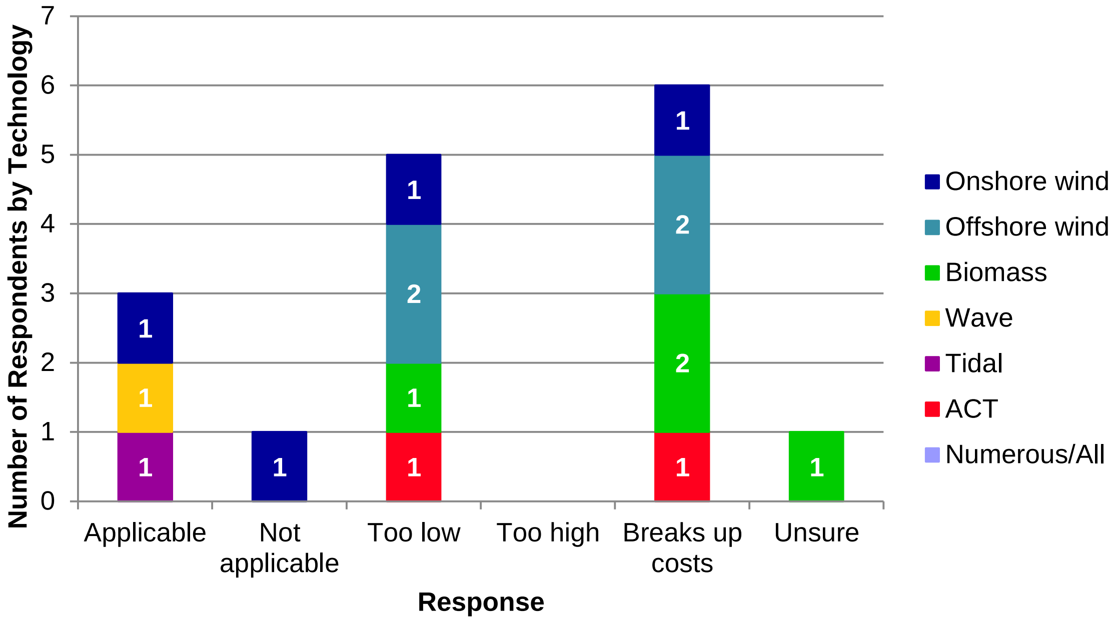
5.5. Responses to Annex A

Annex A has a single question and asks respondents to:

- *"Please state whether the technology costs assumptions made through the ROBR (see Appendix A) are applicable for CfD strike price setting for projects commissioning from 2016/17 onwards."*

Of the 39 qualitative responses, 16 replied to Annex A. Thirteen respondents submitted their Annex A answers in the Excel template and 3 replied in a pdf or word document. Figure 13 shows an overview of our categorisation of the responses to this question, broken down by technology. The categories are explained below.

Figure 13 - Responses to Annex A, "Are ROBR assumptions applicable to CfDs?"[11]



Three respondents stated that the technology cost assumptions made through the ROBR were applicable for CfD strike price setting. These came from a mixture of technologies: 1 wave, 1 wave and tidal and 1 onshore wind. The reasons given for believing technology cost assumptions to be applicable included: the ROBR figures being similar to the respondent's own estimate of costs, or being similar to the costs provided in studies the respondents saw as reliable, for example Arup generation cost study for DECC or the Crown Estate study.

In contrast, 6 respondents believed that cost assumptions were not applicable. Of these, 5 responses from Project Developers suggested that the overall (levelised) costs for their technology in the ROBR assumptions were too low; respondents did not give documented evidence as to why they believed ROBR cost assumptions to be too low. Where they did provide reasons, they stated that the ROBR cost assumptions were different from their own estimates as provided in the quantitative responses or based on previously completed projects and/or cited third party public studies they believed to be reliable (such as the Crown Estate study for offshore wind). 1 response simply stated that cost assumptions were not applicable. The 5 responses that argued ROBR assumptions were too low were from the following technologies: 2 offshore wind, 1 biomass, 1 ACT and 1 onshore wind. The single response arguing that cost assumptions were not applicable was from an onshore wind respondent. In this case, the respondent did not indicate whether cost assumptions were too high or too low but highlighted that 'commercial factors other than technology costs needed to be accounted for in the ROBR assumptions'.

An approach to Annex A adopted by 6 respondents was to break up the different costs in the ROBR assumptions and look at these individually. All of these respondents suggested that some costs were applicable and some too low. None of the responses suggested that any ROBR cost assumptions were too high. There was not a consistent view on which costs were too low or

[11] In categorising the responses, 'Too low' means that the respondent thought that the overall (levelised) costs for their technology in the ROBR were too low (and vice versa for 'Too High')

applicable. However, this may be due to the range of technologies across the 6 responses. The individual responses are summarised below:

- Biomass 1: construction, fixed and variable O&M costs perceived as applicable but fuel costs seen as too low in ROBR
- Biomass 2: costs applicable with the exception of fixed costs which were seen as too low in ROBR (respondent expected these to be 10% higher)
- ACT: fixed and variable costs applicable but ‘understated the values which provide revenue’
- Offshore wind 1: R2 construction and insurance applicable but R3 construction and opex too low in ROBR
- Offshore wind 2: opex applicable and capex too low in ROBR (especially for R2)
- Both onshore and offshore wind: insurance applicable but the other opex and capex figures too low in ROBR

The respondents above did not provide explanation for the reasons they agreed or disagreed with ROBR cost assumptions being applicable for CfD strike price setting. There was a further 1 response (biomass) for which the respondent stated that they did not know whether the ROBR costs estimates were applicable.

To summarise, whilst some respondents thought that the ROBR cost estimates were applicable, at least for particular costs, more respondents thought that the ROBR cost estimates were too low. This is consistent with the observed differences between CfE and ROBR quantitative results.

5.6. Responses to Annex C

Annex C is divided into three questions, which we deal with in turn below, following which we comment on common themes.

5.6.1. Response to Annex C (i)

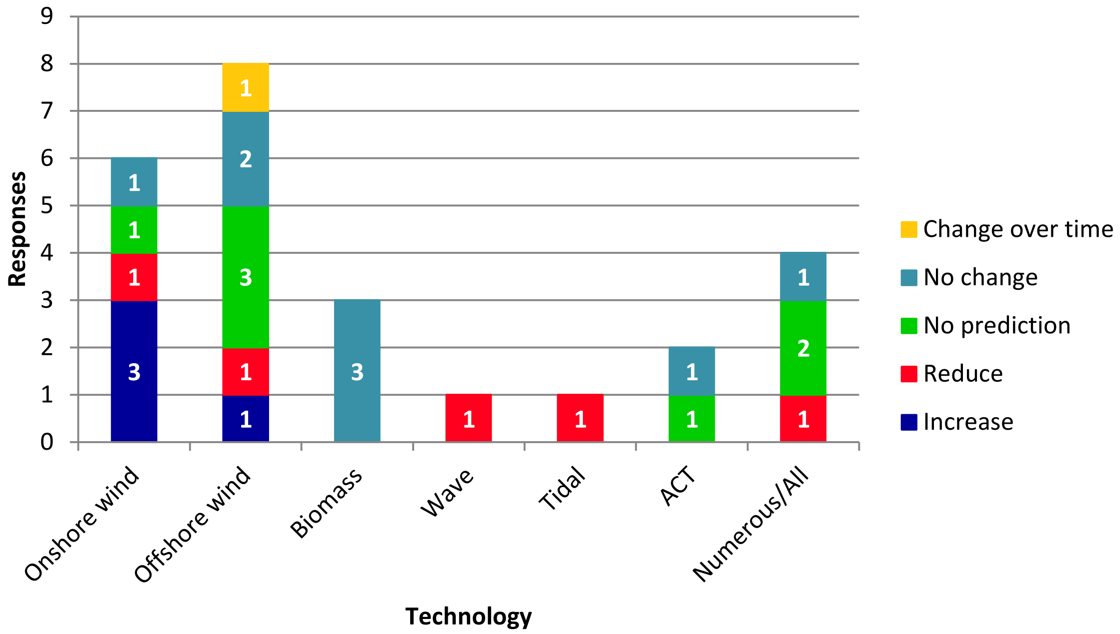
This question asked respondents to:

- *“Please state what levels of reduction in hurdle rate you believe are likely in percentage points [or basis points] in pre-tax real terms [or specify if in other terms] for projects which are supported by CfDs.”*

There were 25 responses to this question. Very few respondents gave the percentage change in hurdle rates that they anticipated for projects supported by CfDs, and so responses were categorised in the following way: high, medium and low reductions, no change, an increase, or respondent does not know. Where provided, we considered the reasons respondents believed hurdle rates to behave in the ways listed above.

Figure 14 shows an overview of the responses to this question, broken down by technology.

Figure 14 - Responses to Annex C (i), "Likely reduction in hurdle rates"



It was common for respondents to highlight the difficulties they experienced with answering this question. One of the main reasons given is the lack of knowledge they believed they had about CfDs. Of the 25 responses, 7 respondents chose not to predict what would happen to hurdle rates. These came from a range of technologies: 3 offshore wind, 2 not aligned to a specific technology, 1 onshore wind and 1 ACT.

Eight respondents did not believe there would be a change in hurdle rates. This position was shared across different technologies: 2 offshore wind, 3 biomass, 1 ACT, 1 onshore wind and 1 without a technology stated. As with the respondents that did not predict hurdle rates, generally the reasons given for 'no change' are respondents' belief that they have a lack of knowledge about CfDs and what will happen, rather than a firm belief that the hurdle rate will not alter at all.

Four of the respondents believed hurdle rates would increase under CfDs. All of these came from wind technology: 3 onshore and 1 offshore. Many respondents considered the relative merits of the RO and CfDs and considered the impact these would have on hurdle rates. Some of the factors regularly stated for increasing hurdle rates included: CfD support being planned for only 15 years despite investment periods being greater than this, and the risk of not being able to sell output and lack of competition in the PPA market leading to unfavourable contracts. This lack of competition in the PPA market will equally affect RO plants so, although it may be believed to contribute to an increase in hurdle rates, this is not solely a CfD issue. Both the 15 year contracts and PPA discounts are explored in further detail in Section 5.7.6.

Five respondents believed that hurdle rates would reduce under CfDs. In contrast to responses suggesting hurdle rates would increase, there was little explanation from respondents as to why they believed hurdle rates would reduce. None of the respondents highlighted very confidently that large reductions in hurdle rates would occur. Three of the 5 respondents believing hurdle rates would reduce considered this would be a low reduction. This was spread across technologies: 1 wave, 1 wind (both types) and 1 without a technology. The remaining 2 respondents (1 wave and tidal and 1 offshore wind) believed a medium reduction in hurdle rates would occur.

Another response, for offshore wind, highlighted that this is something that will change over time as knowledge of CfDs becomes greater and uncertainty reduces, suggesting that hurdle rates might initially increase under CfDs but then have a slow to medium reduction in the long term.

The majority of responses did not answer this question, or stated that, though hurdle rates would not change, they were uncertain. Uncertainty was a common theme in all responses.

5.6.2. Response to Annex C (ii)

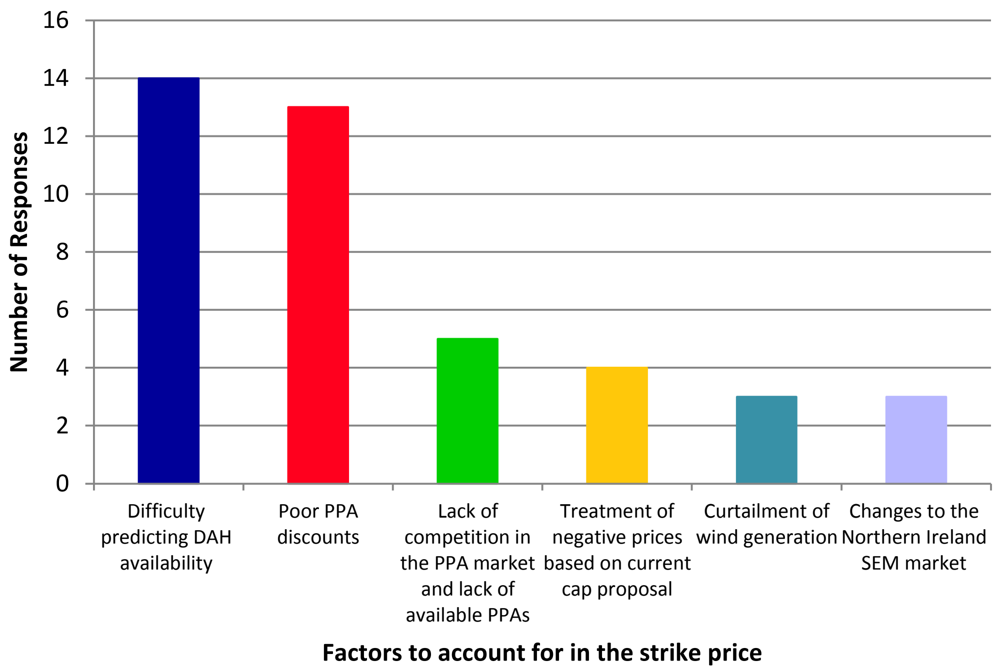
This question asked respondents to:

- *"Please outline any factors that could mean the wholesale prices obtained on the market for renewable technologies may be systematically different from potential CfD reference prices (e.g. due to the load profile of generation being concentrated at times of higher or lower wholesale prices)."*

Of the 28 respondents, 4 believed there were no factors that would mean the wholesale prices obtained on the market may be systematically different from the potential CfD reference prices. These came from the following technologies: 2 ACT, 1 wave and 1 onshore wind.

The other 24 respondents believed that there were factors that could result in a difference between the wholesale prices obtained on the market and the potential CfD reference prices. The factors mentioned most consistently can be seen in Figure 15.

Figure 15 - Responses to Annex C (ii), "Factors effecting ref price vs. strike price"



Difficulty in predicting day ahead availability was mentioned by 14 respondents from technologies that have intermittent generation (wind, wave and tidal). This is cited as a concern because CfDs for intermittent generation will use a Day Ahead reference price, so generators will need to predict day ahead output in order to achieve the reference price. This issue has been explored in further detail in the discussion section of this report (see Section 5.7.5). Large discounts in PPAs, a lack of competition in the PPA market and lack of available PPAs are also picked up in the discussion part of this report (see Section 5.7.6). PPA availability and need for fairly priced PPAs is seen as a concern by most independent developers of renewable energy, and was frequently discussed by respondents.

The treatment of negative prices whereby the reference price is floored at zero (and hence difference payments are capped at the strike price) was raised as a concern by 4 respondents (1 onshore and 1 offshore wind and 2 numerous/all). One respondent (onshore wind) explained what they meant by this, arguing that they would be unable to recover a price commensurate with its long run costs if forced to sell at negative prices in a long market. As wind penetration grows over time, this will increase risk for investors and, in the respondent's view, needs to be factored into the strike price. The response suggested basing payments on availability during period of negative prices to address this risk. Curtailment of wind generation and changes to the SEM market were both mentioned by 3 respondents. These are issues relating to Northern Ireland and again have been picked up in the discussion part of this report (see Section 5.7.7 and Appendix C for more detail).

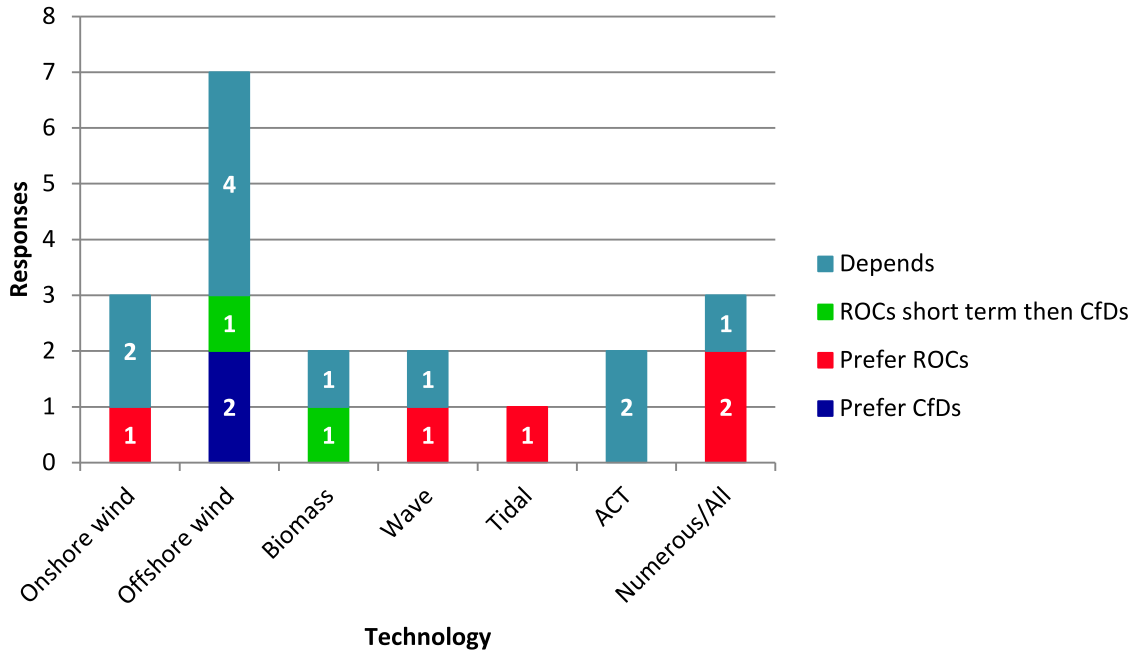
5.6.3. Response to Annex C (iii)

This question asked respondents to:

- *"Please comment on the likely factors that will influence take-up potential of CfDs as opposed to ROCs, which specific projects the stakeholder is likely to prefer under the CfD scheme and the factors that influence such decisions, e.g. would choice depend on:*
    - *Straight financial calculations (the difference in project NPV)*
    - *Developers' and financial institutions' knowledge and experience of the two mechanisms*
    - *Any risk of missing the last date for accreditation under the RO*
    - *Any possibility of FID-enabling products being available*
    - *Or other factors"*

There were 29 responses to this question, coming from a range of technologies. Although the question asked about likely take up factors, many respondents to this question outlined whether they would prefer ROCs or CfDs. This is captured, and broken down by technology, in Figure 16.

Figure 16 – Respondent preference for CfDs or ROCs



Of the 29 respondents, 9 responses did not answer the question, or stated that they did not know, and have been omitted from the figure.

Though not asked for explicitly in the question, seven respondents stated a clear preference for either CfDs or ROCs. The 2 responses preferring CfDs were both for offshore wind. There were 5 responses preferring ROCs: 1 wave and tidal, 1 tidal, 1 onshore wind and 2 without specific technologies.

Two further responses (1 onshore wind and 1 biomass) distinguished between the timescales, and highlighted that in the short term ROCs are preferable. However, when there is greater knowledge about CfDs and they are more established, preferences may change.

Most responses (11, range of technologies) did not select a clear preference for CfDs or ROCs and instead outlined factors that would influence the take-up potential of CfDs as opposed to ROCs. These factors usually incorporated those mentioned in the question, although respondents often added other factors. A benefit of CfDs that was regularly highlighted was 'avoiding volatility'. By some respondents, CfDs were viewed as reducing uncertainty when compared with ROCs because the received price is more stable. On the other hand ROCs were viewed by some respondents as less risky because there is an obligation upon suppliers to buy "renewable power"/ROCs. This was seen as beneficial compared to CfDs, where there is nothing enforcing the purchase of renewable electricity. This is further explored in the discussion Section (5.7) below.

5.7. Further issues raised

The following themes were present in numerous responses, and were not attributed to particular questions.

5.7.1. Lack of clarity about CfDs

Throughout all of the qualitative questions, respondents referred to a perceived lack of clarity about the CfD arrangements. This was especially prevalent for the question where respondents were asked to predict impact on hurdle rates (Ci) and when outlining which factors would lead respondents to choose CfDs as opposed to ROCs (Ciii). This point about lack of clarity was not confined to any technology or region in particular and was found consistently throughout the full range of responses. The following areas are identified as specifically needing clarification and will be considered in more detail below:

- Eligibility criteria
- Contract structure
- Indexation
- Arrangements for the counterparty body
- Application process and timetable.

In Annex A to the November 2012 Energy Bill document, the Government published new information on each of these areas. To allow additional time for respondents to review this material, the original deadline of 10 December 2012 was extended to 7 January 2013, for Annex C only. However a number of responses to Annex C were received alongside the quantitative responses in December. Therefore, there is a reasonable possibility that a number of respondents had not had sufficient time to review the additional information prior to making their submissions (although none mentions this explicitly in their responses).

Eligibility Criteria

There are two parts to the eligibility criteria for CfDs. First, eligible projects must have proof of planning permission and an accepted network connection offer (or equivalent). Second, there is a 'substantive financial commitment milestone and a long stop date for delivery'. This second point may be the less certain of the two as the precise definition of financial commitment had not been determined when responses were prepared. Respondents did not seem to have difficulty in understanding which technologies would be eligible. However, there were some exceptions that referred to projects outside of the UK, or to storage technologies. As discussed in Section 5.4 responses like this were considered out of scope of the CfE and are not included in this report.

Contract Structure

The contract structure was also addressed in Annex A of the Energy Bill (November 2012). This document clearly highlights that the contract will be a 'private law, bilateral contract between the CfD counterparty and an individual low-carbon generator'. These are largely standardised across technologies and are two way.

Indexation

Responses from both onshore and offshore wind and 'numerous/all' technologies highlighted a lack of clarity about strike price indexation to inflation, and what inflation index would be used. Biomass respondents mentioned lack of clarity about indexation to drivers of biomass price (e.g. fuel oil price). The November 2012 EMR document made clear that there would be no indexation except to inflation, however given the timing of the CfE respondents may not have been aware of this point.

Role of the Counterparty

Annex A to the Draft Energy Bill announced that the CfD counterparty will be a limited liability company owned by the Government, with powers to raise funds from suppliers to make CfD payments to generators. This provided some information into how the counterparty will work. However, respondents' concerns were very much surrounding the precise workings of the CfD payment framework, which have not been covered fully in the Draft Energy Bill. An offshore wind respondent commented that it is unclear how the counterparty will be obligated to pay the government. This demonstrates confusion on the part of the respondent because our understanding is that the counterparty body will not pay the Government but instead will receive payments from suppliers and make them to generators. Another respondent for offshore wind suggested that 'mechanisms of payments by the central counterparty' are not clear and a further respondent, for both onshore and offshore wind highlighted that how the counterparty will be kept 'insolvency remote' is not clear and needs further explanation. These comments demonstrate that respondents feel it is necessary to have more clarity on the counterparty arrangements.

Application Process and Timetable

The application process and timetable was also raised by respondents as an area they do not feel they have enough knowledge about. This was often linked to the issue of the timescale for transition between ROCs and CfDs. This is discussed in more detail in Section 5.7.4.

This perceived lack of knowledge about the above areas will have impacted the quality and detail of responses to Annex C questions. Although it will not have affected the cost data, lack of knowledge is explicitly stated by some respondents as making the questions provided too hard to answer. In many cases where respondents have submitted cover letters and pdf documents rather than completing the response template, the respondent has stated that they do not feel they have the information necessary to answer the provided questions.

5.7.2.

5.7.3. CfD support length

Respondents regularly raised the issue of CfD support length being 15 years, as opposed to the 20 year support with the RO. The quantitative responses indicated that investment periods are longer than 15 years and with lifetimes of plants being 20-25 years, respondents highlighted that generators would be exposed to the market for potentially 10 years after CfD support has stopped. One onshore wind respondent mentioned that other countries have financial support mechanisms providing coverage for 20-25 years and this would be necessary for CfDs also. Another respondent, for wave, stated that they would 'tolerate lower strike prices if contracts were 20 years rather than 15 years.'

The reduced support length under CfDs was often seen as the reason hurdle rates would not reduce when compared with ROCs. We presume this is because of expected exposure to wholesale power prices after 15 years. Although under the RO generators will have power price risk for the 20 year period, they still have a high amount of certainty around ROCs and this is a significant proportion of revenues for higher ROC banded technologies, such as offshore wind.

In addition, the reduced support length was stated as a reason not to choose CfDs over ROCs. Again, respondents stated that ROCs offer less uncertainty, and are therefore preferred by many respondents to CfDs.

When setting CfD strike prices, DECC will need to consider whether or not to assume a residual (terminal) value for the asset after 15 years, and how investors may view this residual value.

A 20 year support period is also preferred by some respondents due to being consistent with the Renewable Heat Incentive. This payment is relevant for Dedicated Biomass CHP. However, there is no inherent problem with having support schemes of differing lengths.

5.7.4. Transition between ROCs and CfDs

The Government's stated timetable is for renewable CfD strike prices to be issued and consulted on in the draft delivery plan in July 2013 and finalised by the end of 2013. The first CfDs should be allocated in 2014 and there may be a period of overlap of new plant operating under CfDs and the RO, until the RO closes to new accreditations in April 2017.

Many respondents commented on the transition between ROCs and CfDs. Four respondents (1 onshore, 1 ACT, 2 numerous/all) explicitly stated that the RO should be extended, with 2 respondents offering 2020 as a suggested date. These respondents suggested that extending the RO would give more time for the lack of clarity around CfDs, discussed in 5.7.1., to be resolved. One biomass respondent did not believe the timeline was clear between RO and CfDs and 2 (one biomass and one onshore wind) highlighted that it can take time to 'get comfortable' with new regimes.

Fourteen respondents, from a range of technologies, stated that they do not have the option to choose between ROCs and CfDs, because project development timescales meant that they would miss the last accreditation date for ROCs. They suggested that extending the timescale for ROCs may avoid this problem and would provide generators with greater opportunity to make informed decisions about which method of support is preferable for their projects.

Concerns about the transition between ROCs and CfDs were raised by a mixture of respondents, from ACT, onshore wind and, most commonly, those without a specific technology.

Few respondents distinguished between the short and long term decision making. Two respondents (1 onshore wind and 1 biomass) highlighted explicitly that they would prefer CfDs in the long term but RO in the short term.

5.7.5. Intermittent generation

A difficulty regularly identified by responses for wind, wave and tidal projects was predicting day ahead availability. Many respondents stated that uncertainty in day ahead generation volumes would need to be taken into account in the CfD strike price. For example, 1 offshore wind respondent argued that the difficulty predicting day ahead availability 'would need to be recovered in a higher strike price'. Another respondent for offshore wind stated that the reference price should 'ideally reflect the hourly load profile rather than a simplistic day ahead baseload reference price'. We note that an hourly profiled reference price is the option currently proposed. In order to achieve total revenues close to the CfD strike price, a generator would need to sell power in the wholesale market at the reference price with perfect foresight of its outturn volumes. To the extent that generators are unable to do this, they are exposed to basis risk. Some respondents suggested that the reference price be set at day ahead in order to help reduce some of the risk to generators. Again, this is the current proposal for intermittent generators, but it is clear that not all respondents were not fully aware of this when responding to the consultation in January 2013.

5.7.6. Treatment of PPAs

As many of the respondents were independent developers of renewable energy projects, most rely on long term (e.g. 15 year) PPAs as a route to market. The respondents did not provide explicit values for expected structure and discounts under PPAs. Some respondents were concerned that PPA discounts would not be considered when setting strike prices, and highlighted that these discounts may be significant due to the lack of competition in the PPA market.

There has recently been widespread acknowledgement that the number of counterparties offering long term PPAs to RO generators has declined. DECC's recent CfE on PPAs (June 2012) requested views on this area and a summary of the responses received can be found in Annex A of the Energy Bill document. In brief, the issues reported were:

- Typical discounts have increased on a like-for-like basis.
- Terms used to be 15 years as standard, but are now more likely to be around 10 years.
- Discounts used to be with reference to a year-ahead index, but offers are now against a day-ahead or intra-day index. This introduces a greater degree of price 'cannibalisation' risk for the generator, where the output of the generator is correlated with other intermittent renewables. Price floors, which provide certainty over minimum revenues, were once common, but are now scarce.
- Whilst the numbers of tenders received are reported to be around the same level, or have increased, developers say that fewer of these tenders are 'bankable'. Issues such as whether floor prices are offered or not and the pricing of imbalance risk affect the view of bankability.

Given this background, it is perhaps no surprise that PPAs were regularly raised as an issue to be considered in the CfD CfE. Whilst the lack of available and favourable PPAs is not necessarily specific to CfDs, the CfD does provide different drivers of discounts. Some respondents argued that discounts on the power leg of PPAs could increase since suppliers no longer have an incentive to contract for ROCs.

A number of responses included explicit cost lines in their responses for discounts to revenues under PPAs. An onshore wind respondent highlighted that their own modelling assumed a 10% discount on power revenues. The 5% discount assumed by DECC under ROBR is stated as being too low by another respondent (whose response was not specifically associated with one technology).

5.7.7. Northern Ireland

Respondents from NI raised issues related to the structure of Single Electricity Market SEM covering the island of Ireland. Two responses stated explicitly that they referred to NI. However in some other responses, there were also comments referring to NI.

Curtailment was seen as a much greater issue for CfD generators in NI compared to GB. One respondent highlighted that SONI, the system operator in NI, predicts curtailment to increase to 13.5% in 2016. If this is the case, the respondent felt that they would be penalised under a CfD system based on output rather than availability. Under the current SEM market rules, the generator would not be compensated for lost CfD payments due to curtailment. In contrast in GB if generators are curtailed by the System Operator, they will be compensated to the level of their bid price in the Balancing Mechanism.

In addition to points on curtailment, respondents from NI highlighted that future changes to SEM to align with the European Target Model may produce a different market structure from the current SEM and from the rest of the UK.

APPENDIX A – DATA TABLES

Onshore wind > 5 MW									
		Mean	Min	P_{10}	P_{25}	P_{50}	P_{75}	P_{90}	Max
No. CfE Responses	*-*	*29*							
Predevelopment costs	£/kW	92	21	33	50	84	115	161	210
Predevelopment period	Years	6	3	4	4	6	7	8	9
Construction costs	£/kW	1628	1020	1295	1429	1600	1740	2068	2810
Construction period	Years	2	1	1	1	2	2	2	3
Total opex	£/kW/year	64	33	43	50	64	77	84	100
of which VOM	*£/MWh*	*10.0*	*2.0*	*3.7*	*5.3*	*10.6*	*14.1*	*18.6*	*20.1*
Operational lifetime	Years	24	20	20	21	25	25	25	25
Expected investment period	Years	22	10	20	20	24	25	25	25
Availability	%	97%	95%	95%	96%	97%	97%	97%	98%
Load factor (Net of Availability)	%	29%	27%	27%	28%	30%	30%	31%	33%
Plant Capacity	MW	36	5	10	15	30	60	76	100
Hurdle Rate (Pre tax real)	%	12%	9%	10%	11%	12%	14%	15%	15%

Offshore wind (A)									
		Mean	Min	P_{10}	P_{25}	P_{50}	P_{75}	P_{90}	Max
No. CfE Responses	*-*	*7*							
Predevelopment costs	£/kW	110	67	70	81	100	120	161	200
Predevelopment period	Years	6	4	4	4	5	7	10	12
Construction costs	£/kW	2990	2673	2689	2800	3046	3105	3226	3400
Construction period	Years	4	2	3	3	3	3	5	7
Total opex	£/kW/year	153	80	103	119	143	190	225	230
of which VOM	*£/MWh*	*6.8*	*1.2*	*1.8*	*2.6*	*5.2*	*9.3*	*13.3*	*16.5*
Operational lifetime	Years	22	20	20	20	20	23	25	25
Expected investment period	Years	22	20	20	20	22	24	25	25
Availability	%	94%	92%	92%	93%	94%	94%	95%	96%
Load factor (Net of Availability)	%	43%	38%	39%	41%	44%	45%	47%	48%
Plant Capacity	MW	563	250	275	363	588	719	825	900
Hurdle Rate (Pre tax real)	%	12%	9%	10%	11%	12%	14%	15%	15%

Offshore wind (B)									
		Mean	Min	P_{10}	P_{25}	P_{50}	P_{75}	P_{90}	Max
No. CfE Responses	-	*7*							
Predevelopment costs	£/kW	122	53	54	84	120	133	182	250
Predevelopment period	Years								
Construction costs	£/kW	3378	2900	2932	3017	3258	3423	3969	4612
Construction period	Years								
Total opex	£/kW/year	232	147	170	188	206	236	316	420
of which VOM	*£/MWh*	*1.8*	*1.3*	*1.4*	*1.5*	*1.8*	*2.0*	*2.2*	*2.3*
Operational lifetime	Years	23	20	20	21	24	25	25	25
Expected investment period	Years	23	20	21	22	24	25	25	25
Availability	%	94%	93%	94%	94%	95%	95%	95%	95%
Load factor (Net of Availability)	%	44%	42%	42%	42%	44%	46%	48%	50%
Plant Capacity	MW	992	500	625	800	1000	1163	1350	1500
Hurdle Rate (Pre tax real)	%								

Tidal stream									
		Mean	Min	P_{10}	P_{25}	P_{50}	P_{75}	P_{90}	Max
No. CfE Responses	-	*4*							
Predevelopment costs	£/kW	215	120	122	126	170	259	344	400
Predevelopment period	Years	4	3	3	3	4	4	5	5
Construction costs	£/kW	5340	3790	4174	4751	5536	6125	6350	6500
Construction period	Years	2	2	2	2	2	2	2	2
Total opex	£/kW/year	433	135	146	164	248	517	867	1100
of which VOM	*£/MWh*	*89.7*	*89.7*	*89.7*	*89.7*	*89.7*	*89.7*	*89.7*	*89.7*
Operational lifetime	Years	23	20	20	20	23	25	25	25
Expected investment period	Years	22	20	20	20	20	23	24	25
Availability	%	91%	82%	85%	89%	95%	96%	96%	96%
Load factor (Net of Availability)	%	31%	28%	28%	28%	31%	34%	35%	35%
Plant Capacity	MW	18	10	10	10	15	23	27	30
Hurdle Rate (Pre tax real)	%	12%	12%	12%	12%	12%	12%	12%	12%

Wave									
		Mean	**Min**	**P_{10}**	**P_{25}**	**P_{50}**	**P_{75}**	**P_{90}**	**Max**
No. CfE Responses	-	*4*							
Predevelopment costs	£/kW	112	98	99	101	111	123	127	130
Predevelopment period	Years	4	2	2	3	4	4	5	5
Construction costs	£/kW	7723	6400	6790	7375	7971	8318	8457	8550
Construction period	Years	2	2	2	2	2	2	2	2
Total opex	£/kW/year	219	104	127	162	229	286	301	311
of which VOM	*£/MWh*	*10.0*	*10.0*	*10.0*	*10.0*	*10.0*	*10.0*	*10.0*	*10.0*
Operational lifetime	Years	21	20	20	20	20	21	24	25
Expected investment period	Years	21	20	20	20	20	21	24	25
Availability	%	90%	80%	83%	88%	91%	94%	96%	97%
Load factor (Net of Availability)	%	30%	27%	28%	29%	31%	32%	32%	33%
Plant Capacity	MW	18	10	10	10	15	23	27	30
Hurdle Rate (Pre tax real)	%	11%	10%	10%	11%	11%	12%	12%	12%

APPENDIX B – DATA BENCHMARKS

The quantitative data received through the CfE was compared against a number of previous studies into the cost of renewable generation. The key sources presented in this report are the Renewable Obligation Banding Review (ROBR), and The Crown Estate Cost Reduction Pathway.

ROBR figures have been taken for 2016/17, and are presented verbatim in Table 13.

The Crown Estates Cost Reduction Pathways study has 256 discrete data points for offshore projects and associated costs. These were averaged to give comparative data for offshore wind A and B technologies, following discussions with Richard Howard of The Crown Estate. Table 10 below describes the approach taken to average the data points, while Table 11 gives the consolidated costs for comparison.

Table 10 - Consolidation of Crown Estates cost data

Parameters	Options	Offshore wind A	Offshore wind B
Story	1 (slow progression), 2 (tech acceleration), 3 (supply chain efficiency) 4 (rapid growth)	Average all (all similar in 2014)	Average all (all similar in 2014)
Turbine size (MW)	4, 6, 8, 10	Average 4 & 6	Average 4 & 6
FID date	2011, 2014, 2017, 2020	2014 (commission ~2017)	2014 (commission ~2017)
Site type	A (25m deep, 40km from shore) B (35m, 40km) C (45,m 40km) D (35m, 125km)	Average A & B	Average C (deep) & D (far from shore)

Table 11 - Crown Estate average costs for comparison with CfE

Selected Scenario:		Sites A&B (CfE Offshore wind A)	Sites C&D (CfE Offshore wind B)
Pre-development Costs	£/kW	150	150
Construction Costs	£/kW	2508	2687
Total opex	£/kW/year	157	198
Load factor (Net of Availability)	%	43%	47%

Table 13 - ROBR cost estimates

Cost/parameter	Pre-development costs			Construction costs			Fixed O&M	Variable O&M	Insurance	Connection and UoS	Heat revenue	Efficiency	Load factor pre-availability	Availability	Operational lifetime	Construction Time
Units	£/kW			£/kW			£/MW/y	£/MWh	£/MW/y	£/MW/y	£/MWh	%	%	%	Years	Years
Commissioning year	All years			2016/17			2016/17	2016/17	2016/17	2016/17	2016/17	All years	All years	All years	All years	All years
Low/medium/high	L	M	H	L	M	H	M	M	M	M	M	M	M	M	M	M
Onshore wind >5MW [1]	21	32	110	1,200	1,500	1,800	15,000	3	6,500	10,300	*N/A*	*N/A*	*25.5% E&W; 28.6% S; 33.3% NI [3]*		24	2
Offshore wind R2 [2]	46	70	120	2,000	2,300	2,700	63,000	2	12,000	46,000	*N/A*	*N/A*	*N/A*	94%	23	3
Offshore wind R3 [3]	49	100	150	2,500	2,900	3,500	71,000	*[7]*	33,000	61,000	*N/A*	*N/A*	42%	95%	22	3
Biomass conversion/ enhanced co-firing	58	58	58	270	440	750	41,000	1	1,300	17,000	*N/A*	36%	[5]	75%	22	1
Dedicated biomass <50MW	38	96	110	2,500	3,600	5,100	110,000	5	17,000	1,600	*N/A*	31%	[5]	90%	25	2
Dedicated biomass >50MW	16	31	38	2,000	2,500	4,600	96,000	4	14,000	1,400	*N/A*	36%	[5]	90%	25	3
Dedicated biomass CHP [4]	*Included in construction*			2,700	3,900	5,000	150,000	10	25,000	*[7]*	51	20%	93%	90%	25	3
Standard co-firing			2	40	120	170	10,000	1	920	9,200	*N/A*	37%	[5]	85%	9	1
Co-firing with CHP [4]	*Included in construction*				4,300		260,000	2	*[7]*	*[7]*	108	20%	90%		25	2
Hydro >5MW without storage		53			3,100		44,000	*[7]*	*[7]*	*[7]*	*N/A*	*N/A*	36%	98%	41	2
Hydro >5MW with storage		53			3,400		25,000	6	920	7,300	*N/A*	*N/A*	45%	98%	41	2
Wave [6]			280	3,600	4,400	5,200	180,000	*[7]*	68,000	750	*N/A*	*N/A*	30% [3]		20	2
Tidal stream shallow [6]	280	330	380	3,100	3,700	4,500	180,000	*[7]*	56,000	750	*N/A*	*N/A*	40% [3]		20	3
Tidal stream deep [6]	390	510	620	4,200	4,800	5,500	130,000	*[7]*	83,000	750	*N/A*	*N/A*	40% [3]		20	2
Geothermal	46	140	300	2,300	4,600	6,700	36,000	11	71,000	2,000	*N/A*	*N/A*	*N/A*	94%	25	3
Geothermal CHP	46	140	240	2,600	5,100	7,300	34,000	10	77,000	1,900	86	*N/A*	*N/A*	94%	25	3
PV > 5MW [7]	14	21	28	850	910	1,010	20,000	*[7]*	*[7]*	*[7]*	*N/A*	*N/A*	*N/A*	98%	25	1
AD	54	180	580	1,700	4,000	7,200	300,000	31	58,000	8,700	*N/A*	*N/A*	36%	90%	21	1
AD CHP [4]	54	180	580	1,800	4,200	7,200	360,000	21	58,000	8,700	22	*N/A*	36%	90%	21	1
Advanced ACT	165	410	1,010	5,100	6,800	6,900	410,000	13	22,000	5,600	*N/A*	26%	87%		24	2
Standard ACT	170	360	1,010	930	5,600	#####	430,000	24	22,000	5,600	*N/A*	22%	89%		24	2
ACT CHP [4]	86	86	86	980	5,900	#####	430,000	24	22,000	5,600	24	19%	87%	89%	24	2
Bioliquids	33	180	1,000	480	800	1,900	120,000	6	4,900	12,000	*N/A*	28%	89%	81%	10	1
Bioliquids CHP [4]	33	180	1,000	500	840	2,000	120,000	6	4,900	12,000	13	28%	89%	81%	10	1
Energy from Waste	*Included in construction*			4,500	4,900	5,200	220,000	24	*[7]*	*[7]*	*N/A*	24%	92%	90%	31	3
Energy from Waste CHP [4]	*Included in construction*			5,500	6,200	6,900	270,000	29	*[7]*	*[7]*	18	20%	95%	90%	30	3
Landfill gas	34	130	210	1,000	2,000	3,400	60,000	9	1,300	5,100	*N/A*	*N/A*	36%	92%	20	1
Sewage gas	*Included in construction*			2,300	3,600	5,900	101,000	*[7]*	*[7]*	8,700	*N/A*	*N/A*	36%	85%	28	2

All data rounded to 2 significant figures

[1] Fixed opex is for years 1 to 5. Assumed to increase for years 6 to 24 up to £33,500/MW/y

[2] Early R3 with R2 type site conditions included in R2

[3] Load factors net of availability

[4] With CHP QA heat offtake for separate demand (on or offsite)

[5] Endogenous to electricity market despatch modelling using assumed SRMCs and SRMRs

[6] Marine technologies pre-development costs assumed to reduce over time. Data above is for average of 2016/17 and 2017/18.

[7] Included in fixed costs

APPENDIX C – NORTHERN IRELAND

Northern Ireland respondents face slightly different challenges to respondents from the rest of the UK. Therefore, we have summarised the data from Northern Ireland respondents separately as shown in Table 12 below.

Table 12 - Summary of NI quantitative responses

		All Onshore			NI only			Excluding NI		
		L	**M**	**H**	**L**	**M**	**H**	**L**	**M**	**H**
No. CfE Responses	-	*29*			*4*			*25*		
Predevelopment costs	£/kW	33	84	161	56	78	128	33	88	162
Predevelopment period	Years	4	6	8	7	8	8	4	5	7
Construction costs	£/kW	1295	1600	2068	1652	1875	2119	1258	1500	1940
Construction period	Years	1	2	2	1	2	2	1	2	2
Total opex	£/kW/year	43	64	84	46	50	60	42	64	85
of which VOM	*£/MWh*	*3.7*	*10.6*	*18.6*				*3.7*	*10.6*	*18.6*
Operational lifetime	Years	20	25	25	25	25	25	20	25	25
Expected investment period	Years	20	24	25				20	24	25
Availability	%	95%	97%	97%				95%	97%	97%
Load factor (Net of Availability)	%	27%	30%	31%				27%	30%	31%
Plant Capacity	MW	10	30	76	12	20	50	10	30	77
Hurdle Rate (Pre tax real)	%	10%	12%	15%				10%	12%	15%