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Glossary

Acronym	Term
AEP	Annual Energy Production
AI	Artificial Intelligence
AR6	Allocation Round 6
AR7	Allocation Round 7
BloombergNEF	Bloomberg New Energy Finance
BoP	Balance of Plant
Capex	Capital Expenditure
CfD	Contract for Difference
COD	Commercial Operations Date
DCO	Development and Consent Order
DESNZ	Department for Energy Security and Net Zero
Devex	Development Expenditure
DUoS	Distribution Use of System
EBITDA	Earnings Before Interested, Tax, Depreciation, and Amortisation
EPC	Engineering, Procurement, and Construction
EU	European Union
FID	Final Investment Decision
FX	Foreign Exchange
GB	Great Britain
GDP	Gross Domestic Product
GW	GigaWatt
GWp	GigaWatt-Peak
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IoT	Internet of Things
IRENA	International Renewable Energy Agency
kW	KiloWatt
kWp	KiloWatt-Peak
LCOE	Levelised Cost of Electricity
LPA	Local Planning Authority
MW	MegaWatt

MWh	MegaWatt-Hour
MWp	MegaWatt-Peak
NDA	Non-Disclosure Agreement
NSIP	Nationally Significant Infrastructure Project
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OFTO	Offshore Transmission Owner
OFW	Offshore Wind
ONS	Office for National Statistics
Opex	Operational Expenditure
PPA	Power Purchase Agreement
REA	Renewable Energy Association
SGRE	Siemens Gamesa Renewable Energy
SRMC	Short-Run Marginal Costs
TNUoS	Transmission Network Use of System
TSO	Transmission System Operator
UK	United Kingdom
UoS	Use of System
WTG	Wind Turbine Generator

1. Executive summary

1.1 Context

In February 2024, Arup was commissioned by the Department for Energy Security and Net Zero (DESNZ) to update the Levelised Cost of Electricity (LCOE)[1] for onshore wind, offshore wind and large-scale solar PV (>5MW) technologies in Great Britain out to 2050. This report specifically focuses on offshore wind only and the findings on onshore wind and solar technologies are provided in a separate report (Arup, 2025). The purpose of this study was to collect up-to-date costs and technical assumptions to enable the update of LCOE figures which inform DESNZ's policy decisions and its energy system modelling.

The LCOE for offshore wind has been falling since 2010; however, there has been upward pressure on the LCOEs of offshore wind (and similarly for onshore wind and solar) technologies since 2022. This has been driven by macroeconomic global price shocks, the lingering effects of COVID-19 (particularly in China), volatile commodity costs, supply chain issues, rising labour costs, elevated interest rates increasing the cost of capital, and persistently high inflation.

Arup conducted an independent assessment using data from stakeholder engagement, published sources, and internal benchmarks. This study builds on previous cost and technical assumption studies, including the Electricity Generation Costs Report 2023 (DESNZ, 2023a) and the Review of Renewable Electricity Generation Cost and Technical Assumptions carried out by Arup in 2016 (Arup, 2016).

The LCOE estimates presented in this report were calculated using DESNZ's published LCOE tool along with technology-specific data which were gathered over 2023 and 2024 using a standardised methodology. The LCOEs Arup has estimated do not necessarily reflect the final results adopted by DESNZ for its future publications; DESNZ may choose to apply different assumptions for some parameters. The figures presented in this report should therefore be interpreted as key inputs into DESNZ's broader cost and technical analysis rather than final forecasts adopted by the department.

1.2 Stakeholder engagement

To inform this study, Arup undertook a targeted stakeholder engagement process, contacting over 100 organisations across the renewables sector. This included developers and key technology suppliers, with participation further encouraged through engagement with relevant trade associations.

The stakeholder survey formed the backbone of this research, given the importance of evaluating costs and assumptions most relevant to future UK projects. Hence, a range of measures were applied to maximise reach across relevant developers and to facilitate their provision of a high-quality return.

Trade associations such as the Renewable Energy Association (REA), RenewableUK, Scottish Renewables, and Energy UK also shared our communications with their members helping to increase the number of responses. Additionally, Arup arranged a virtual drop-in session during which developers could ask questions about the questionnaire and raise concerns.

To further enhance the legitimacy of the study and encourage participation, Arup provided Non-Disclosure Agreements (NDAs), recognising that much of the requested information was confidential. Once signed, Arup shared a standardised questionnaire with developers (see Appendix A.1).

A key enhancement since the 2016 Arup led study was the involvement of a dedicated stakeholder engagement specialist, who refined the survey approach to better align with the needs of the renewable

[1] LCOE can be defined as the discounted lifetime cost of building and operating a generation asset, expressed as a cost per unit of electricity generated (£/MWh). It covers all relevant costs faced by the generator, including predevelopment, capital, operating, fuel, and financing costs. It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

energy sector. This contributed to a higher response rate. In 2024, 6 offshore wind developers, compared to 5 previously. The overall participation in this study is summarised in Table 1 below.

1.3 Summary of responses

Arup's analysis relied on responses provided by stakeholders (primarily renewable energy project developers), in combination with the assessment of benchmark data and in-house expert judgement. The stakeholder engagement process encouraged participation from project developers, which resulted in a sample of projects covering all three technologies. Data for onshore wind and solar can be found in Arup (2025). Arup received responses from 20 developers (noting that some respondents covered multiple technologies), covering 55 projects across the three technologies. A summary of these responses for offshore wind is illustrated in Table 1 below, highlighting the number of responses received, total capacity, and geographic regions covered across each technology type.

Arup aimed to test the information provided by developers with that from suppliers. However, only four responses were received from suppliers, and these did not include detailed cost information for benchmarking. This limitation restricted our ability to compare developer data with supplier data.

Table 1: Summary of responses

Category	Offshore Wind[2]
Responses received	10
Number of developers	6
Total MW	11,760
Regions	England and Scotland

This study focused exclusively on fixed-bottom offshore wind projects. This decision was made due to the recent study on cost and technical assumptions for floating offshore wind conducted by Frazer Nash in 2023 (Frazer-Nash Consultancy, 2023). Arup identified an increased risk of bias in the offshore wind results, which is discussed in Section 1.6.

1.4 Criteria for identification and inclusion of data

Arup applied a rigorous, multi-stage process to ensure the integrity and representativeness of the cost and technical data used to estimate LCOE values. An initial review of all questionnaire responses assessed the stakeholder interpretation, consistency across responses, and standardisation of cost data to 2023 prices. Responses were checked for completeness, correct units, formatting consistency, and outliers. Clarifications were sought directly from stakeholders where values did not align with benchmarks.

Following this, a structured framework was implemented to determine the inclusion of data. This comprised six scenarios, each applying progressively more selective filters. These were used to define the final dataset for cost and technical assumptions. The scenarios applied a combination of the following inclusion criteria:

- **No duplicates or zeros:** No zeros and no duplicate responses from the same developer.
- **Technology-specific:** Responses must be technology-specific and within scope, ensuring that the data provided pertain to the technology assessed (e.g. only fixed-bottom offshore wind projects were included).
- **Reasonable response:** Data points must pass Arup's test for reasonability, where internal experts validated the data based on their expertise. Where data points were removed using this filter, explicit

[2] Excluding responses received for floating offshore wind projects which were subsequently removed from the analysis.

notes have been included in the report to ensure the rationale is clear and to ensure traceability of the results.

- **Current cost:** Data points must reflect costs that are as current as possible, thus omitting costs heavily influenced by recent macro-economic pressures. A more detailed explanation is provided in Subsection 3.3.5.
- **Arup's benchmark:** Data points must fall within the range of Arup's benchmark. Details on the type and number of projects used to calculate this benchmark are provided in Section 5.
- **External benchmark:** Data points must fall within the range of the externally published industry benchmarks~~,~~ which included reports from reputable sources. Where applicable, these are included in each technology chapter.

Subject matter experts assessed each scenario and, through discussion with DESNZ, selected the most appropriate data subset to provide robust low, medium, and high estimates for each category.

Crucially, Arup defined **"current costs"** as those accurate at present, as of 2023-2024. In particular, costs which are up-to-date and are based on presently valid assumptions (i.e. if developers were to request quotes in the market between 2023 and 2024). The intention of focusing on this timeframe was to (i) attempt to remove or reduce the impact of the macroeconomic shocks between 2020 and 2022 and (ii) focus on the current technology rather than future scenarios dependent on hypothetical innovations.

To determine if project costs are recent and aligned with the years 2023 to 2024, Arup utilised the COD provided by developers in their questionnaire responses to estimate when costs had been derived. By subtracting the typical construction period range (as provided by stakeholders) and the likely time needed to negotiate contract prices (assessed with input from subject matter experts), Arup calculated a range of CODs which have been assumed to represent current costs, see Subsection 3.3.5 for more detail. This approach allowed Arup to isolate costs aligned with the present market and technological environment, ensuring the LCOE estimates are both timely and credible.

Table 2 below presents the number of project responses, highlighting how many were classified as reflecting "current costs" based on their Commercial Operations Dates (CODs).

Table 2: Project responses identified as satisfying the definition of "current cost"

Technology	COD range	Project responses	Projects with COD in current cost range
Offshore Wind	2028 to 2032	10	8

1.5 Summary of results

1.5.1 Costs and technical assumptions

The tables below present the current costs[3] and technical assumptions for the low, medium and high scenarios. The cost figures represent the current costs for 2023-2024 and are in real terms 2023, with no adjustment made to capital or operational expenditure to account for future learning rates[4]. In this study, Arup aimed to ensure costs are up-to-date and are based on presently valid assumptions (i.e., the costs if developers were to request quotes in the market between 2023 and 2024 prior to reaching project financial close[5]).

[3] Arup considered current costs to be those from projects with CODs between 2028 and 2032. See Subection 3.3.5 Current Costs for more details.
[4] For more information on data precision and the intended use of the results presented in this report, please refer to Section 3.10 of the methodology.
[5] In this context, financial close refers to the process of formalising all financial agreements, contracts and commitments. It represents the end of the procurement phase of the project and the point in which the project moves into the construction phase. Arup has assumed that there is between 0.5 – 1 year between final quotes being received and financial close. When accounting for a technology-specific period of construction, the current costs have been derived from responses received with COD of 2028-32 for offshore wind. See Section 3.3 for more details.

Table 3: Summary of 2023-2024 current costs and technical assumptions for offshore wind in this study

Category	Unit	Offshore wind		
		Low	Medium	High
Costs				
Pre development	£/kW	104	216	308
Capital costs during construction	£/kW	2,415	2,823	3,101
Infrastructure costs[6]	£/kW	802	937	1,030
Total Capex	£/kW	3,321	3,976	4,439
Insurance	k£/MW/a	8.0	8.6	9.7
Connection and UoS charges	k£/MW/a	35.3	83.4	132.9
O&M	k£/MW/a	30.5	46.5	64.6
Total Opex	k£/MW/a	73.7	138.5	207.2
Technical assumptions				
Net load factor[7]	%	46.0%	50.5%	56.1%
Operating lifetime[8]	years	35	35	35
Additional assumptions				
Hurdle rate[9]	%	6.2%	6.2%	6.2%
Predevelopment timescale	years	7	7	15
Construction timescale	years	4	5	5

1.5.2 LCOE results

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. As described in Section 3.7, LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

[6] For offshore wind, there is a different arrangement for the capture and allocation of transmission cost. Offshore transmission owner (OFTO) construction costs for the electricity transmission cable are excluded from the analysis as OFTO payments are made via the payment of local and wider TNUoS charges, which are included within the operating costs. This avoids double counting the cost of offshore transmission assets. Note that any profit associated with the sale of the OFTO is not considered in this analysis and could ultimately result in a reduction in overall LCOE for offshore wind projects.

[7] As part of this study, Arup calculated net load factors based on survey results. However, it is understood that DESNZ will use its own internal data and modelling to inform the net load factors applied in in their LCOE calculations.

[8] For offshore wind operating lifetime, the stakeholder responses all indicated 35 years

[9] Hurdle rates were calculated by Arup using BloombergNEF's H2 2023 LCOE data, published for the UK (BloombergNEF, 2024a) post-tax nominal debt and equity assumptions. These were converted from post-tax nominal to pre-tax real terms, following the methodology set out in BEIS's 2018 Cost of Capital report and assuming 2% inflation and a 25% corporate income tax rate. Hurdle rates were assessed through literature review only and were not included in the survey, as DESNZ was undertaking separate work on this topic, the results of which were not available at the time. Note that Hurdle rates may vary over time depending on specific asset dynamics, where the asset is in its development lifecycle or movements in the macro-economic environment including cost of capital or changes to the regulatory environment. Therefore, rates now may be different to those referenced through a desktop review from BloombergNEF's H2 2023 data.

The results are shown below in Table 4. These scenarios are designed to be indicative and to offer a range of LCOE estimates for comparison with current LCOE scenarios in industry literature. Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Table 4: LCOE, based on current costs 2023-2024 (2023 real prices £/MWh)

Case	Offshore wind
Low	55.4
Medium	88.5
High	124.0

1.6 Assessment of data confidence, uncertainty and limitations

Arup's primary objective was to produce current central LCOE values that reflect current costs and deployment trends. Given the specific nature of the responses, the findings inherently include uncertainty and may not fully represent projects in other geographies or with different characteristics. To mitigate this, Arup employed internal and external benchmark data, alongside insights from subject matter experts, to validate all results. This ensured that even when results were inconsistent with projects reviewed by Arup or found in the literature, internal experts could assess their accuracy based on specific characteristics and recent trends.

The pool of survey respondents must be considered when assessing the risk of bias in survey responses leading to higher cost estimates. While we have sought to validate developer responses and compare them against industry benchmarks and data, some positive bias may remain. For offshore wind this could be particularly difficult whereby the developer pipeline is concentrated and there is a small sample of results (see further details in Subsection 3.5). Whilst the data points do sit within benchmarks, caution should be applied when considering the central case result, as it may not be representative of a generic future project. Arup recommends applying a range of results and provide sensitivities cases around this central view.

Despite the successful gathering of valuable data for LCOE modelling, certain challenges influenced the scope and detail of the analysis. These included:

1. Number of responses received.
2. Potential bias in the data provided.
3. Limited engagement from suppliers.

Cost and technical assumptions provided by stakeholders were carefully validated to mitigate potential bias. All data supplied by developers were cross-checked against internal and external benchmarks to ensure reliability. Arup also looked across the responses to determine whether any of respondent provided consistently above-average costs, which could potentially skew results. This was primarily a concern for offshore wind. However, although evaluation was made more difficult by the small number of responses, this specific point was not regarded as problematic since most above-average responses were explainable by the technical characteristics of the projects. In cases with limited responses, Arup relied more on internal expert judgement, industry understanding, and assessment of the latest literature and benchmarks.

It is also important to note that, in any survey, responses may be influenced by human factors such as differences in individual interpretation of questions, optimism or pessimism bias, or strategic positioning. Such factors are inherent in qualitative research and should be considered when drawing firm conclusions from the data. We have aimed to present the results transparently, without attributing motive; we encourage the reader to consider the broader context when interpreting the findings.

Offshore wind farms are large in scale but fewer in number. This naturally resulted in a smaller pool of potential respondents. Consequently, it would only require a small number of respondents to be unrepresentative of the population in order to skew results. This introduced a high risk of potential bias in the offshore wind results.

Capex is susceptible to bias due to the impact of a project's characteristics on its construction cost. Whilst factors such as water depth, distance from port and onshore grid connection point, and transmission system also affect Opex, the implications for Capex are more significant.

To understand whether bias had been introduced into the offshore wind results, Arup investigated the site specific characteristics, assessing across Capex categories. Arup noted the following considerations as a result of this investigation:

- Two of the responses related to "generic" or "exemplar" projects. It is possible that theoretical projects such as these will not capture potential costs as reliably as defined projects.
- Within this filtered sample of six projects, half of the wind farms utilised jacket foundations. These are typically a more expensive solution than monopiles, which have historically been the more popular choice.
- Similarly, half of the wind farms in the filtered sample were located in deep water (~60 metres). Deeper waters coincide with greater engineering complexity and material requirements and in turn, in all likelihood, greater Capex.
- The filtered sample also included a mix of HVAC and HVDC projects. HVDC transmission systems are generally more expensive than their HVAC counterparts, with the benefit of lower transmission losses over large distances. Grid connection distances ranged from 30km to 160km with an average of c.85km, indicating long distances from the project to grid connection point.
- Only England and Scotland were represented within this filtered sample. This means the findings do not account for potential cost variations specific to offshore wind farms in Welsh waters.

Connection and Use of System charges (TNUoS) for offshore wind are location specific and responses represent a broad range of results. The uncertainties surrounding the approach to future UoS charging regime also increases uncertainty of how this should be considered. The prevalence of jacket foundations, deep water, and HVDC transmission systems in the filtered sample could have resulted in increased Capex particularly when compared to analysis carried out in previous years. As potential nearshore sites become less available and developers resort to deeper and more distant locations, these site characteristics are becoming increasingly more common. Nevertheless, Arup remained cognisant of potential bias and the influence of site-specific characteristics on a project's LCOE. This was therefore investigated and addressed through the mitigants discussed in Subsections 3.5.2 and 3.5.3, ultimately resulting in a range of low, medium, and high sensitivities, reflecting the uncertainty in the findings.

1.7 Future outlook

The future outlook of renewable energy costs is important when assessing the LCOE. The understanding of future cost trends can help policymakers and investors make informed decisions about energy infrastructure investments, subsidies, and long-term planning.

As part of this research, Arup asked stakeholders for their views on how costs have evolved since 2021, their expectations up to 2035, and from 2035 to 2050. Responses were largely qualitative in nature and covered predevelopment costs, construction costs, and operational costs.

As described in the report's Section 4, historical cost reductions experienced across the renewable energy industry do not reflect the evolving macro-economic situation since 2021, which has resulted in increased cost for renewable energy projects.

For offshore wind, the analysis is based on a combination of qualitative and quantitative data provided by stakeholders, supplemented with industry views and Arup's in-house expertise.

The future outlook of offshore wind is represented by a range of possible scenarios based on quantitative and qualitative views provided by stakeholders. It appears that although technological advancements are continuing in the wind industry, driving efficiencies and higher performance, there is uncertainty related to the impact of other factors such as supply chain constraints, inflationary pressures and increased financing costs. This is reflected in the stakeholder responses and has resulted in underlying uncertainty of achieving short-term cost savings, hence, immediate cost reductions are not considered to be the medium case. Operations and maintenance (O&M) cost reductions are expected to continue based on review of industry literature, which forecasts continued efficiencies relating to technology advancements.

In the tables below, Arup has presented low, medium and high scenarios representing stakeholder views for offshore wind technology.

Note that the years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured and costs finalised, prior to a project reaching financial close[5]), unless stated otherwise. These years do not correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.

Another example could be a project securing costs in 2030 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close) where a 97.5% Capital Cost factor and 80.0% Fixed O&M cost factor should be applied through multiplication, to the "current costs" (as defined above) resulting in a lower capital and operating cost.

Table 5: Learning rates for capital and fixed O&M costs based on stakeholder views

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Capex projections						
Low case	100.0%	98.3%	94.2%	90.0%	85.0%	75.0%
Medium case	100.0%	100.0%	100.0%	100.0%	95.8%	87.5%
High case	100.0%	101.7%	105.8%	110.0%	106.7%	100.0%
Opex projection						
Fixed O&M	100.0%	94.5%	82.4%	73.9%	67.6%	59.2%

1.8 Comparison of LCOE estimates

1.8.1 Approach

Arup has carried out a comparison of the LCOE for offshore wind based on Arup's 2023-2024 cost and technical assumptions analysis against a blended average of LCOEs from global and UK literature and the Electricity Generation Costs 2023 report from DESNZ (DESNZ, 2023a). The comparison reveals variations across the different sources, highlighting recent trends and regional impacts on LCOE.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

Note that for the low, medium, and high scenarios the hurdle rate was kept consistent (see individual technology chapters for details), therefore further sensitivity cases exist based on this financial metric and should be considered as required. This approach allowed Arup to assess the impact of changes in cost and technical assumptions on LCOE.

To reflect the inherent uncertainty in these inputs, Arup developed low, medium, and high scenarios for each cost and technical parameter. These input scenarios were then used to calculate corresponding low, medium, and high LCOE estimates for each technology. The resulting range illustrates the potential variability in generation costs and highlights that the central case should not be interpreted as a definitive value. Arup suggests that, when considering generation costs, sensitivities should be assessed within this range, as the central/medium case alone does not represent the full breadth of possible outcomes.[10]

As discussed in Section 1.6, whilst we have sought to validate developer responses and compare them against industry benchmarks and data, some bias may remain.

1.8.2 Results

Table 6: Offshore wind LCOE comparison (2023 real prices)

Offshore wind	Arup 2023 - 2024	Literature	DESNZ 2023[11]
Low LCOE (£/MWh)	55.4	56.8	39.4
Medium LCOE (£/MWh)	88.5	84.9	43.9
High LCOE (£/MWh)	124.0	113.6	48.4

For offshore wind, Arup's LCOE is 88.5 £/MWh, which is 4% higher than the blended literature average of 84.9 £/MWh. The Arup LCOE is 102% higher than DESNZ's estimate (DESNZ, 2023a) of 43.9 £/MWh.

Note, these DESNZ estimates do not include the adjustments made after the AR6 CfD auction round. See Section 5.7.2 for more detail.

Given that there is a significant difference in the LCOE derived from Arup 2023-2024 assumptions, the blended literature and the DESNZ 2023 estimates (DESNZ, 2023a), Arup carried out further analysis of the underlying responses to assess the data confidence, potential bias and uncertainty. To fully understand differences requires understanding the individual parameters incorporated into the estimation of LCOE. See sections 1.6 and 3.5 for more details.

[10] Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

[11] DESNZ projection for commissioning year 2030 was used, as this aligns best with Arup's "current cost" filters.

2. Introduction

In February 2024, Arup was appointed by the Department for Energy Security and Net Zero (DESNZ) to undertake a comprehensive Levelised Cost of Electricity (LCOE) study. LCOE is per unit cost of electricity generated over a project's life, taking into account costs, electricity generation, asset life, and discount rate[12]. The objective of this study was to estimate current generation costs and technical assumptions that enable the update of LCOE for onshore wind, solar PV, and offshore wind in Great Britain. This report specifically focuses on offshore wind and the findings on onshore wind and solar technologies are provided in a separate report (Arup, 2025). In addition, the outlook of costs has been considered up to the year 2050 reflecting the current state of the supply chain as well as technology variations and advances.

Arup's work involved an independent assessment, drawing upon data obtained through stakeholder engagement processes, as well as leveraging both published and internal sources. The analysis conducted as part of this study enabled the development of new estimates for generation costs and the LCOE associated with renewable electricity generation projects spanning the next three decades.

The findings from this study will play a crucial role in informing DESNZ's policy decisions and strategic planning related to renewable technology support by the UK government. DESNZ requested that this review and assessment be compared to previous work, including DESNZ's last published review of generation costs conducted in the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a), along with explanation of where methodology or assumptions may have changed.

2.1 Context

The renewable energy sector has seen significant growth in recent years, with offshore wind technology playing a pivotal role. Over the past decade or more, the LCOE for these technologies has generally been on a downward trajectory, making them increasingly competitive with traditional energy sources. However, recent macroeconomic global price shocks following the lingering effects of COVID-19 (particularly in China), volatile commodity costs, supply chain issues, rising labour costs, elevated interest rates, capital and persistently high inflation have increased costs and placed pressure on renewables developers. This has resulted in LCOE increases across offshore wind as well as onshore wind and solar technologies since 2021.

The impact of these price spikes has varied per geography, and in scale and length per technology, with wind developers, particularly offshore, still dealing with inflated prices and elevated LCOEs (BloombergNEF, 2024a; IEA, 2023; IRENA, 2023; Lazard, 2024).

Offshore wind technology has seen a substantial decline in LCOE since 2010, with a 59% decrease globally and a 71% drop in the UK from 2010-2022 (IRENA, 2023). This decrease was driven by volume, larger turbines, increased capacity factors, and technological advancements contributing to more efficient site design and reduced O&M costs. However, the recent volatility in commodity prices, including high steel prices, has particularly impacted turbine prices in the UK and Europe, leading to increased LCOE for offshore wind from 2022 to 2024 (BloombergNEF, 2024a).

In summary, although the LCOE for offshore wind has historically been on a downward trend, recent macroeconomic factors have caused short-term increases. This context will inform the costs and technical assumptions used for the analysis in this report.

2.2 The project

The primary focus of this study was to update the costs and technical assumptions necessary for generating LCOE estimates. Arup undertook a comprehensive approach, beginning with an extensive review of industry literature to summarise the latest developments in renewable energy technologies. This review provided a

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[12] LCOE can be defined as the discounted lifetime cost of building and operating a generation asset, expressed as a cost per unit of electricity generated (£/MWh). It covers all relevant costs faced by the generator, including predevelopment, capital, operating, fuel, and financing costs. It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

foundation for gathering new project costs, considering the critical information related to capital expenditure, operating expenditure, and load factors. Additionally, supplementary data, including land costs, property and business rates, taxes, and specific technology details such as turbine information, were collected to ensure a robust analysis aligned with DESNZ's objectives.

A significant aspect of the study was the stakeholder engagement process, which played a crucial role in the analysis. The stakeholders involved in this project included developers of offshore wind, as well as technology suppliers and trade associations which helped extend our reach to more developers. Arup received strong engagement from project developers, with help from trade associations; however, there were no responses from technology suppliers that could be used in the analysis.

Arup relied on stakeholders to provide their most accurate estimates of costs for new renewable projects. While the data from stakeholders served as the primary source, they were tested against published benchmarks and internal knowledge to validate their suitability for LCOE estimation. Chapter 3 of this report details the methodology used to analyse and generate a representative set of costs and technical assumptions.

Data for the study were gathered from various sources. Over 100 stakeholders were contacted using a standardised questionnaire, the details of which are provided in Appendix A.1.

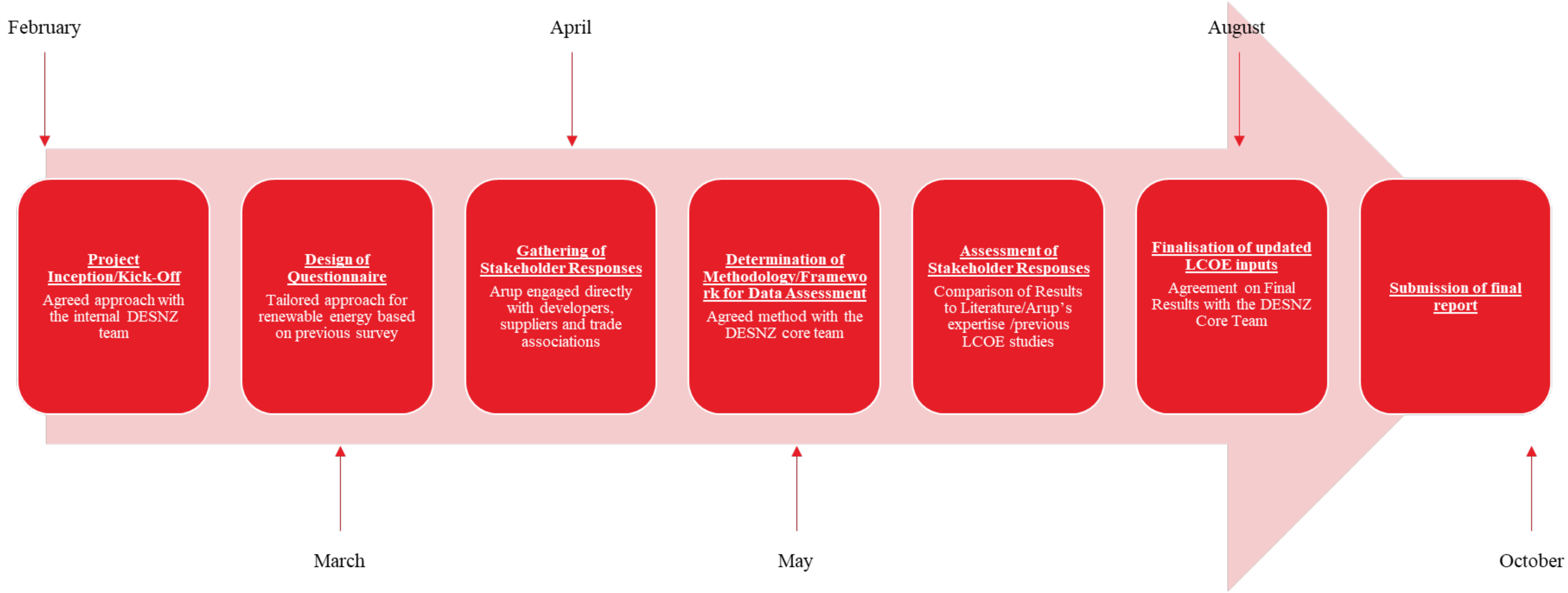
Additionally, Arup utilised insights from external entities such as Bloomberg New Energy Finance (BloombergNEF), the International Renewable Energy Agency (IRENA), the International Energy Agency (IEA), and Lazard. Arup also reviewed internal data on renewable generation costs and performance to supplement the analysis.

Lastly, to assess how LCOE might change over time, Arup developed a future outlook for capital and operating costs. This forecast was primarily informed by stakeholder views. The analysis considered both increasing and decreasing cost trends to provide a comprehensive outlook on future LCOE.

3. Methodology

This chapter provides a summary of the Arup methodology used to develop a representative set of renewable data. The objective is to outline the approach and logic employed to derive the cost and technical assumptions presented in this report. The main steps in the methodology are shown in the diagram below:

Figure 1: Arup's 2024 study methodology timeline



3.1 Research design

This section provides an overview of the method for collecting primary data via stakeholders which are active in the development of renewable generation technology, specifically offshore wind, onshore wind and large solar PV (>5MW) projects.

Stakeholders were asked to provide data via a questionnaire regarding the cost, timeline, and technical assumptions for bringing a project from predevelopment (i.e. the planning stage) through to construction and operation. This allowed Arup to form a view of the lifecycle cost and performance of each technology. Arup used the methodology from the Arup (2016) study as a basis, tailoring it to focus solely on renewable generation technology by including specific questions relating to offshore wind updating where necessary. This approach enabled Arup to gather more granular data, specifically identifying views around supply constraints in the near future, such as for panels, inverters, and transformers.

The survey was split between Part A, which focussed on collecting new data, and Part B, which focussed on collecting stakeholder views on future developments in technology, cost, and performance. The aim was to collect sufficient reliable data for a representative lifecycle cost for each technology to be produced.

To ensure consistency in the responses, Arup conducted verified the integrity and validity of the stakeholder data. This involved verifying values were entered correctly, reviewing figures against internal knowledge, and raising follow-up questions with stakeholders where necessary.

Part B of the questionnaire asked stakeholders to provide commentary (both qualitative and quantitative) around their expectations for future changes in cost as well as the key drivers behind these changes. Examples of cost drivers include supply chain effects, commodity prices, and labour.

For the levelised cost calculations, Arup maintained consistency with previous Electricity Generation Cost studies, by employing the template provided by DESNZ. This common template was used across technologies to capture data consistently for each cost category. It is important to note that, three values (low, high, and medium) were calculated for each key timing and technical datum needed for determining the cost of electricity in order to ensure consistency and coverage of the range of potential outturn results. Further elaboration on this topic can be found in Section 3.3.

3.2 Stakeholder engagement process

As part of the stakeholder engagement process, Arup contacted over 100 organisations, including developers of renewable energy projects and suppliers of key components for these projects. To increase participation and response rates, Arup also engaged with trade associations representing these developers and suppliers. The contacted developers spanned across onshore and offshore wind technologies, ensuring a comprehensive representation of the sector.

Arup shared a standardised questionnaire with developers (see Appendix A.1). Suppliers received a tailored set of questions (see Appendix A.1), designed to address the specific context of their contributions to the sector. Over 30 technology suppliers were contacted, including wind turbine manufacturers, cable suppliers and inverter manufacturers.

Four responses were received, covering cables, inverters and mounting structures; however, the information provided did not include cost details that could be used for benchmarking. This limited our ability to contrast the information provided by developers with this data. This may have been due to the commercial sensitivity of product costs and prices, lack of incentives for the suppliers to respond, or because suppliers were contacted later in the process, with less time to respond.

Arup arranged a virtual drop-in session during which developers could ask questions about the questionnaire and raise concerns. Other trade associations such as the Renewable Energy Association (REA), RenewableUK, Scottish Renewables, and Energy UK also confirmed that they had shared our communications with their members.

To further enhance the legitimacy of the study and encourage participation, Arup provided Non-Disclosure Agreements (NDAs), recognising that much of the requested information was confidential. We were flexible in using either our own NDA as a standard or those provided by specific respondents if they so wished.

A main difference between the 2016 and 2024 studies has been the involvement of an Arup stakeholder engagement expert with experience in participatory design, who formulated the surveys to maximise the benefit for all parties. The questionnaire focused solely on renewable energy technologies, rather than across a wide range of generating technologies (as previously) and was tailored to effectively engage stakeholders.

Arup received questionnaire responses from 20 developers (noting that some respondents covered multiple technologies), regarding 55 projects across the offshore wind in conjunction with onshore wind and solar technologies, including 10 offshore wind projects.

3.3 Criteria for identification and inclusion of data

Prior to using the cost and technical assumption data for LCOE modelling, an examination of the questionnaire responses was carried out to ensure the dataset's integrity. The evaluation included:

- **Stakeholder interpretation:** Correct interpretation of the questionnaire. For example, verifying that the respondent provided a response that is in line with the question asked.
- **Data range and consistency**: Consistency across different datasets was checked using data plots to view the range of responses. This enabled extreme values to be more readily identified and examined as potential outliers.
- **Cost uniformity:** To enable meaningful comparisons, the cost base was standardised by inflating or deflating where necessary.

Note that at this stage, no data were excluded. Subsequently, the questionnaire data were reviewed following a framework for data utilisation to ensure accurate and representative results, free from bias and based on current costs, not influenced by recent macro-economic pressures.

- **Framework for data utilisation:** This is the defined framework for assessing the data, presenting a range of scenarios and ultimately the final subset of data to be included within the cost and technical assumption estimates.

The points below summarise our approach in more detail.

3.3.1 Stakeholder interpretation

A review of the questionnaires indicated that most stakeholders provided the requested data accurately. However, in a small number of instances where values did not align with internal and external benchmarks, clarification was sought via email exchange directly with the stakeholders. Arup has reviewed each questionnaire and established its overall usefulness to the study in terms of providing accurate information for cost and LCOE modelling.

3.3.2 Data range

Arup's initial step was to generate a scatter plot of the cost and technical assumptions collected. This was presented in a dashboard, facilitating the identification of extreme values and allowing Arup to assess the range of responses. Outliers were identified through evaluation against data points from other suppliers, whether other responses from the same developer aligned, and the degree to which they were outside benchmarking range; otherwise, these data were retained.

3.3.3 Cost uniformity

Arup's approach involved reviewing each questionnaire to ensure consistency across the dataset. This included verifying the data were in the same format, currency, and cost base. For cost-related questions, Arup expressed a preference for receiving data that is as current as possible, based on firm offers, contracted prices, or incurred amounts. Developers were also asked to provide the base year and describe the indexation mechanism assumed if the cost base year was not 2023. This allowed us to adjust nominal terms to real 2023 where necessary. Predevelopment, capital, and infrastructure costs were expressed in £/kW, and operating costs in k£/MW/a. For indexing, the GDP deflation factors from December 2023 published by the Office for National Statistics (ONS) were used. Note that developers primarily responded in real terms 2023, meaning minimal adjustment was required.

3.3.4 Framework for data utilisation

After the initial evaluation of the data, Arup developed a framework to determine which data points would be utilised for the study. This framework consisted of six scenarios, each with minimum requirements for data inclusion, and was applied to all costs and technical assumptions provided as outputs to DESNZ.

For each scenario, Arup subject matter experts assessed the range of scenarios and subsequently recommended which results should be used for the calculation of the LCOE.

The scenarios were developed using a defined set of filters.

- **No duplicates or zeros:** No zeros and no duplicate responses from the same developer.
- **Technology-specific:** Responses must be technology-specific and within scope, ensuring that the data provided pertain to one of the technologies assessed (e.g. only fixed-bottom offshore wind projects were included).
- **Reasonable response:** Data points must pass Arup's test for reasonability, where internal experts validated the data based on their expertise. Where data points were removed using this filter, explicit notes have been included in the report to ensure the rationale is clear and to ensure traceability of the results.
- **Current cost:** Data points must reflect costs that are as current as possible, thus omitting costs heavily influenced by recent macro-economic pressures. A more detailed explanation is provided in Subsection 3.3.5.
- **Arup's benchmark:** Data points must fall within the range of Arup's benchmark. Details on the type and number of projects used to calculate this benchmark are provided in Section 5.
- **External benchmark:** Data points must fall within the range of the externally published industry benchmarks~~,~~ which included reports from reputable sources. Where applicable, these are included in each technology chapter.

Table 7: Scenarios considered

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
No duplicates or zeros	X	X	X	X	X	X
Technology specific	X	X	X	X	X	X
Reasonable response		X	X	X	X	X
Current cost			X	X	X	
Arup benchmark				X		X
External benchmark					X	

Arup subject matter experts reviewed each of the scenarios and, through discussions with DESNZ, determined the most appropriate scenario to use, providing a single estimate of the low, medium, and high values for each of the cost and technical assumptions to be used in the subsequent LCOE modelling.

This approach ensured that data points outside our internal benchmarks or external industry benchmarks, yet sufficiently close to be considered possible by experts, were still considered in the analysis.

It is important to note that even though different scenarios were selected depending on the category, most of the scenarios selected were either scenario 2 or scenario 3.

3.3.5 Current costs

In recent years, there have been global price shocks (see Section 4) that have directly influenced the cost to develop renewable energy projects. Considering the main objective of this research – to determine the "**current costs"** that influence the LCOE of renewable energy projects – it was deemed essential to develop a method to identify **"current costs"** from within the stakeholder responses.

The aim was to remove data points from historical cost data (prior to 2022), attempting to ensure that costs are as current as possible and are therefore as free as possible from the price-shocks caused up to 2022. To do this, it was decided to use the projects' Commercial Operations Date (COD) to determine if the costs are potentially historical in nature and thus potentially influenced by the price shocks. The detailed explanation of what constitutes current costs and how they were determined is provided in this subsection.

Arup defined **"current costs"** as those accurate at present, as of 2023-2024. In particular, costs which are up-to-date and are based on presently valid assumptions (i.e. if developers were to request quotes in the market between 2023 and 2024). The intention of focusing on this timeframe was to (i) attempt to remove or reduce the impact of the macroeconomic shocks between 2020 and 2022 and (ii) focus on the current technology rather than future scenarios dependent on hypothetical innovations.

To determine if project costs are recent and aligned with the years 2023 to 2024, Arup utilised the COD provided by developers in their questionnaire responses to estimate when costs had been derived. By subtracting the typical construction period range (as provided by stakeholders) and the likely time needed to negotiate contract prices (assessed with input from subject matter experts), Arup calculated a range of CODs which have been assumed to represent current costs (see Figure 2).

Methodology for Determining COD Ranges

Arup followed a systematic approach to determine the COD ranges for each technology:

1. **Review of responses**: Arup first reviewed the stakeholder responses to ensure they were robust and reliable.
2. **Calculation of COD ranges**: Using the typical time required to negotiate prices and the typical construction period range from the surveyed responses, Arup employed a bottom-up approach to calculate the COD ranges.
3. **Assessment of data points**: Arup then assessed the number of responses within the identified COD ranges to determine the sufficiency of data points for cost calculations.
4. **Adjustment of COD ranges**: If too few data points were identified, the upper end of the dataset was checked to see if additional data points could be included, ensuring the results were consistent with the existing data within that category. In these cases, this suggests that projects in the near future beyond current costs would have a similar cost in this category.

As a result, the COD range was extended by one year to ensure a sufficient number of data points. For offshore wind, the construction period typically spans 4 – 5.3 years. Prices are negotiated in the final stages of predevelopment, approximately 1 year before construction begins. Based on this, Arup considered current values to be those from projects with CODs ranging from 2028 to 2032. This estimation aligns with costs defined between 2023 and 2024. For this specific technology, it was decided by the subject matter experts to round up the 5.3 to broaden the data points considered in this study.

Some of the project information received did not represent current costs. For instance, an offshore wind project with a COD in 2026 would not have costs considered as current. Given the typical construction period of at least four years, coupled with an additional year for price negotiations, it is likely that predevelopment, capital, and operating expenditures for such a project were calculated or incurred no later than 2021. Consequently, these costs do not accurately reflect the industry landscape for the years 2023-24. The data outside of this COD range were still analysed and may prove useful for other purposes, but they were not used to inform the LCOE.

Note that through this process, the CODs were rounded to the nearest integer and the upper end of the COD range was informed by the stakeholder responses and Arup subject matter experts. This approach ensured that sufficient data was processed, and that the results reflected current technology trends, rather than extrapolating too far into the future.

This methodology differs from previous data selection methods used in Arup's earlier studies, wherein macroeconomic pressures and the resultant price fluctuations were of a lesser concern.

Figure 2: COD ranges used to derive current costs

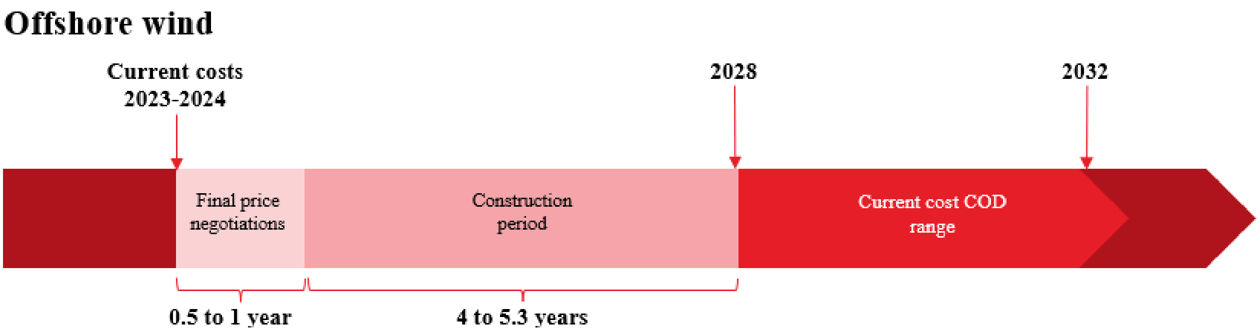


Table 8 below presents the number of project responses, highlighting how many were classified as reflecting "current costs" based on their Commercial Operations Dates (CODs).

Table 8: Project responses identified as satisfying the definition of "current cost"

Technology	COD Range	Total number of project responses	Projects with COD in current cost range
Offshore Wind	2028 to 2032	10	8

3.4 Categorisation of outputs

Cost and technical assumptions were categorised into low, medium, and high values based on the designated scenario and dataset used.

The medium value was determined using either the mean or median of the dataset, depending on the total number of data points available for the analysis. If the dataset contained fewer than ten data points, the mean was chosen. For datasets with ten or more data points, the median was used. Although the Arup-derived method recommended using the mean for smaller datasets, an evaluation of the underlying distribution and expert judgement were also considered to ensure accuracy. In one instance, this rule was overruled in favour of the median. Specific details on the method used for each category are provided in the respective technology chapters.

This approach was chosen with the aim of finding a "middle" or "typical" value. The median can be a better measure of the "typical value", when a large dataset is being measured (i.e. the middle point) and is less susceptible to being skewed by outliers. Conversely, for smaller datasets, the mean can serve as a more reliable central indicator. For example, with values of 1, 5, and 20, the median would be five, while the mean would be nine, which may provide a more representative central value.

Arup calculated the 5th and 95th percentiles of cost figures based on the survey responses. Using percentiles was necessary to derive low and high values and to anonymise the cost data provided by the developers. However, for time periods and other technical assumptions, Arup chose not to apply a 5th or 95th percentile because these are less easily identifiable metrics than cost; instead, minima and maxima were used. Each technology chapter explains in detail which cost or technical assumptions used the minimum or 5th percentile, and which used the maximum or 95th percentile.

3.5 Assessment of data confidence, uncertainty and limitations

This section evaluates the confidence and uncertainty of the data gathered from developers in this study, reflecting the diversity of responses in technology and geography.

3.5.1 Summary of responses

Arup's analysis relied on responses provided by stakeholders (primarily renewable energy project developers), in combination with the assessment of benchmark data and in-house expert judgement.

The stakeholder engagement process encouraged participation from project developers, which resulted in a sample of projects covering offshore wind, onshore wind and solar technologies. Arup received responses from 20 developers (noting that some respondents covered multiple technologies), covering 55 projects across the three technologies (for onshore wind and solar refer to Arup (2025). A summary of these responses is illustrated in Table 9 below, highlighting the number of responses received for offshore wind, total capacity, and geographic regions covered.

Table 9: Summary of responses by technology type

Category	Offshore wind[13]
Responses received	10
Number of developers	6
Total MW	11,760
Regions	England and Scotland

Offshore wind farms are larger in scale but fewer in number compared to onshore wind or solar projects. This naturally resulted in a smaller pool of potential respondents. Consequently, it would only require a small number of respondents to be unrepresentative of the population in order to skew results. This introduced a high risk of potential bias in the offshore wind. Arup has presented a range of results (low, medium and high), reflecting the uncertainty of the findings and the range of possible outcomes. Arup suggests that, when considering generation costs, sensitivities are assessed within this range, as the central/medium case alone does not represent this broad range of results.

Capex is susceptible to bias due to the impact of a project's characteristics on its construction cost. Whilst factors such as water depth, distance from port and onshore grid connection point, and transmission system also affect Opex, the implications for Capex are more significant.

As discussed in Subsection 3.3.5, data were filtered to ensure only "current costs" were considered for the assessment of Capex, which further reduced the number of data points (for offshore wind this reduced ten responses to six). The smaller size of this filtered sample introduced elevated uncertainty for the offshore wind results.

To understand whether bias had been introduced into the offshore wind results, Arup investigated the site-specific characteristics, assessing across Capex categories. Arup noted the following considerations as a result of this investigation:

- Two of the responses related to "generic" or "exemplar" projects. It is possible that theoretical projects such as these will not capture potential costs as reliably as concrete projects.
- Within this filtered sample of six projects, half of the wind farms utilised jacket foundations. These are typically a more expensive solution than monopiles, which have historically been the more popular choice.
- Similarly, half of the wind farms in the filtered sample were located in deep water (~60 metres). Deeper waters coincide with greater engineering complexity and material requirements and in turn, in all likelihood, greater Capex.
- The filtered sample also included a mix of HVAC and HVDC projects. HVDC transmission systems are generally more expensive than their HVAC counterparts, with the benefit of lower transmission losses over large distances. Grid connection distances ranged from 30km to 160km with an average of c.85km, indicating long distances from the project to grid connection point.
- Only England and Scotland were represented within this filtered sample. This means the findings do not account for potential cost variations specific to offshore wind farms in Welsh waters.

Connection and Use of System charges (TNUoS) for offshore wind are location-specific and the responses represent a broad range of results. The uncertainties surrounding the approach to future UoS charging regime also increases uncertainty of how this should be considered. The prevalence of jacket foundations, deep water, and HVDC transmission systems in the filtered sample could have resulted in increased Capex, particularly when compared to analysis carried out in previous years. However, as potential nearshore sites become less available and developers resort to deeper and more distant locations, these site characteristics

[13] Excluding responses received for floating offshore wind projects

are becoming increasingly common. Nevertheless, Arup remained cognisant of potential bias and the influence of site-specific characteristics on a project's LCOE. This was therefore investigated and addressed through the mitigants discussed in Subsections 3.5.2 and 3.5.3, ultimately resulting in a range of low, medium, and high sensitivities, reflecting the uncertainty in the findings.

3.5.2 Mitigating uncertainty in the updated costs, technical assumptions and resulting LCOE calculation

Arup's primary objective has been to produce cost and technical assumptions to enable current central LCOE values ("medium" or "typical" case) that reflect current costs and deployment trends in terms of location, technology, and other technical characteristics.

Given that the responses received are specific to particular renewable energy generation sites, or in some cases generic sites, the findings from the modelling inherently include uncertainty and may not fully represent projects in other geographies or with different characteristics.

Arup employed internal and external benchmark data, alongside insights from subject matter experts, to validate all results. This ensured that even when the results were inconsistent with projects reviewed by Arup or found in the literature, our internal experts could assess their accuracy based on specific characteristics (e.g. site size) and recent trends known or expected by the experts.

As described above in Section 3.4, to reflect the range of stakeholder responses, Arup has provided low and high values for each of the updated cost and technical assumptions that are used within the LCOE analysis.

In addition, effective minima (low case) and maxima (high case) scenarios have been established by combining the relevant low and high data inputs. This enabled us to present the full range of uncertainty surrounding the LCOE figures. This approach generated a broad range of results, ensuring that costs and assumptions from projects at both ends of the spectrum were considered and utilised.

3.5.3 Overcoming data collection challenges

Despite the successful gathering of valuable data for LCOE modelling, certain challenges influenced the scope and detail of the analysis. These included the number of responses received, the potential for bias in the data provided, and the limited engagement from suppliers. With these variables, a range of strategies were employed to ensure the robustness of the findings. These are outlined below.

- **Limited number of responses in some categories:** As is typical in stakeholder engagement exercises, certain data limitations were encountered in specific categories with limited responses (e.g. predevelopment period in offshore wind). In these cases, Arup relied more on internal expert judgement, understanding of the industry along with assessment of latest literature and industry benchmarks.

  All cases where expert judgement, benchmarks or proportional approach were used are detailed in the relevant technology subsections. In addition, the total quantity of data received, as well as the data points used to calculate each cost and technical assumption, have been included in each technology chapter for clarity.

- **Mitigating potential bias in responses:** Cost and technical assumptions provided by stakeholders were carefully validated to mitigate potential bias. All costs and technical data supplied by developers were crosschecked against internal and external benchmarks to ensure reliability. Arup applied its judgment to stakeholder data to establish representative cost and technical parameters for each technology. The rigorous approach to data inclusion is described in Section 3.3. Arup's internal benchmarks consisted of projects located across the United Kingdom and other relevant markets with Commercial Operations Dates within the ranges considered current, as outlined in Subsection 3.3.5. To further enhance the validity of the data, internal experts were consulted, especially when benchmarks were limited. In addition, for offshore wind, the individual site characteristics were assessed to investigate the potential of bias introduced by the smaller sample size of responses, as described further in Subsection 3.5.1.

- **Addressing limited supplier engagement:** Arup aimed to test the information provided by developers with that from suppliers. However, only four responses were received from suppliers, and these did not include detailed cost information for benchmarking. This limitation restricted our ability to compare developer data with supplier data. To mitigate this, Arup relied on internal and external industry benchmark data and performed an in-depth literature review to test and ensure the robustness of the stakeholder data and the resulting analysis.

  It is important to note that supplier perspectives are generally limited to specific parts of projects (e.g. foundations or transformers), rather than the holistic view that developers have, and thus we believe their restricted engagement did not materially impact results.

- **Ensuring geographical representativeness:** From the stakeholder data, for fixed-bottom offshore wind projects, three were in Scotland and seven in England. This geographical distribution provided valuable insights and is considered to be representative of the project locations currently under development in Great Britain, although the number of responses was relatively limited and did not include projects in Welsh waters. Despite these challenges, Arup undertook thorough data validation, employed internal benchmarks, and engaged subject matter experts to assure data quality and robust analysis. Cross-checking results with recent literature and benchmark data ensured alignment with the industry, taking into account broader trends. This comprehensive approach reinforced the robustness of the LCOE calculations and provided a solid foundation for the findings in this study. Nevertheless, Arup remained cognisant of potential bias and the influence of site-specific characteristics on a project's LCOE ultimately resulting in a range of low, medium, and high sensitivities, reflecting to some extent the uncertainty in the findings.

3.6 Levelised cost of electricity

The levelised cost of electricity (LCOE) generation is a metric used to analyse the average cost of electricity generation by different technologies over their lifetime for a generic plant. It can be defined as the discounted lifetime cost of building and operating a generation asset, expressed as a cost per unit of electricity generated (£/MWh). It covers all relevant costs faced by the generator, including predevelopment, capital, operating, fuel, and financing costs.

It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

Project timing is an important dimension for the development, delivery and operation of a project. The following were factored into the calculation:

- The estimated time it takes for a project to go through design, construction, and delivery.
- The expected operational life of the technology in question.
- The discount rate which allows the valuation of future values to be brought back to present values i.e. the value today of a future stream of costs. The discount rate was not derived through stakeholder responses but through external literature, as described in Chapter 4.

Arup produced low, medium, and high estimates for input into an LCOE model (the Model) as described in Section 3.7. LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

Please note that a review of learning rates has been carried out to provide a future outlook review. A summary of the analysis is presented in Section 3.9.

3.6.1 Components of LCOE

This subsection outlines the main components of LCOE (cost or technical assumptions) and provides an approach which is consistent with the approach previously adopted by DESNZ. The calculation comprises the following items:

- **Devex:** The development cost of a project, which includes achieving planning permission and compliance with regulatory requirements.
- **Capex:** The capital cost of bringing a generator to operation, including any associated infrastructure costs for grid connection.
- **Opex:** On-going costs of operating a renewable generator and keeping it available for generation. These also include costs relating to operations and maintenance, insurance, connection. and Use of System (UoS) charges.
- **Load factor:** Load factor, which is defined as the ratio of average annual output to the total potential output if a plant were to operate at full capacity over its lifetime, when accounting for all site-specific loss adjustments. For LCOE specifically, net load factor should be utilised as this typically provides a central estimate of the actual annual energy yield. Arup considers this approach more representative compared to that of the Electricity generation costs report from DESNZ (DESNZ, 2023a), where LCOE has been calculated using the gross load factor with an availability loss adjustment only. There was a higher response rate in the survey for net load factor compared to gross annual load factor and a lack of detailed responses regarding loss factors. Below are the net load factors:
    - **Net load factor for wind energy**: Typically accounts for all relevant loss factors, including system availability (Wind Turbine Generator (WTG), Balance of Plant (BoP), and Grid), wake losses (internal and external), electrical system losses, turbine performance losses, and other secondary factors. Definitions of typical loss factors can be found at the European Academy of Wind Energy website (EAWE, 2021)). Specific details of site-specific loss factors such as locational grid curtailments are not provided; however, the net load factors provided are expected to include any constraint losses, particularly those that are not compensated. For compensated losses it is likely that developers do not include these in the net load factor, but this cannot be known definitively.
- **Time periods:** Predevelopment (from project initiation, through the design and permitting phase, to final investment decision (FID) and start of construction), construction (through to COD) and operational time periods (up to decommissioning), along with how costs are distributed across these periods.
- **Gross power:** The gross power output, which represents the total electrical power that a wind farm can produce under ideal conditions, without factoring in inefficiencies or other losses. This is used, along with the net load factor, to determine the annual energy production.
- **Operational life:** The plant's operational life, which refers to the duration for which a wind farm remains active and produces electricity.
- **Plant availability[14]:** The wind farm's availability, which is an energy-based measure of the maximum potential time a plant is available to generate electricity annually. This factor varies depending on how the plant is operated and the amount of downtime required for maintenance.

3.6.1.1 Predevelopment costs

In the context of this study, predevelopment costs refer to expenses incurred before the construction of a renewable energy farm. These costs are critical for project planning and include the following components:

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[14] Note that plant or system availability is already accounted for as a loss within the net load factor and therefore is not used directly within the LCOE estimation.

- Pre-Licensing Costs and Technical Design:
  - Expenses related to obtaining necessary permits, approvals, and licenses from regulatory authorities.
  - Costs associated with engineering design, feasibility studies, and technical assessments.
- Regulatory, Licensing, and Public Inquiry Costs:
  - Fees for complying with legal and regulatory requirements specific to the renewable energy project.
  - Expenses incurred during public consultations and local community engagement processes.

In this analysis, we aggregated these two cost categories to present a singular total predevelopment cost. This decision was influenced by the higher response rate from developers regarding total development expenditure. Detailed information on the number of responses per subcategory and the overall development expenditure will be provided in each technology chapter.

Exclusions: Note that predevelopment costs do not include land lease, acquisition expenses, seabed option fees, subsequent seabed rental fees, property and business rates, tax costs, rental fees, or community benefit payments. These were asked independently and the results of these are included in each technology chapter. This is understood to be consistent with the approach taken in previous LCOE analyses carried out on behalf of DESNZ.

3.6.1.2 Capital costs

Capital costs for a renewable energy farm encompass the total expenses required for construction and bringing the facility into operational status. Based on the stakeholder questionnaire, capital costs for LCOE modelling were assumed to include two main components:

- Capital cost, which includes project design, procurement, and EPC expenses. In addition, other capital costs such as site works, roads, and utility connections were also captured here.
- Infrastructure cost, which is a separate line item within the LCOE model. It comprises grid connection expenses (e.g. underground cable costs), the local substation, and transformer stations. The boundary of infrastructure is assumed to include the site where the generator is located, associated electrical infrastructure and connection to the nearest point on the grid. For offshore wind, the Offshore Transmission Owner (OFTO) construction costs for the electricity transmission cable are excluded from the analysis as OFTO payments are made via the payment of local and wider TNUoS charges, which are included within the operating costs. This avoids double counting the cost of offshore transmission assets.

The capital costs include contingency; however, specific values were not always provided by survey respondents.

Exclusions: capital costs do not include land acquisition expenses or seabed lease fees, property and business rates, tax costs, rental fees, interest costs during construction or community benefit payments. These were asked independently and the results of these are included in Section 5.

3.6.1.3 Operating costs

Operating costs represent the ongoing expenses associated with the day-to-day operation of a renewable energy farm. These costs encompass the following:

- O&M costs:
  - Fixed O&M costs: These include labour, planned maintenance, a limited number of unplanned maintenance activities, spares, and consumables.
  - Variable O&M costs: These costs are related to output and include additional O&M expenditures, although these are generally not significant to renewable energy projects.

In this study, fixed and variable O&M costs have been combined into a single O&M figure, based on the responses received. This is due to a combination of not receiving a sufficiently detailed breakdown of costs from the stakeholder responses. This could also reflect that stakeholders do not cost projects using the variable £/MWh metric. This combined approach aligns with the analyses of other industry bodies, such as BloombergNEF and Lazard.

- Insurance costs: These cover the cost of insuring the generation plant, protecting against risks associated with its operation and maintenance.
- Network Use of System (UoS) charges: These are the costs associated with connecting to and using the distribution and transmission networks. The UoS cost reported in Arup's analysis includes local and wider Transmission Network Use of System (TNUoS) and Distribution Use of System (DUoS) costs, calculated as a £/MW/annum. It should be noted that the UoS charges are highly site-specific and are heavily dependent on location and grid connection. This analysis does not take into account or estimate system-wide costs.

Exclusions: operating costs do not include land acquisition expenses or seabed lease fees, property and business rates, tax costs, rental fees, or community benefit payments. These were asked independently and the results of these are included in Section 5.

3.7 LCOE scenarios

DESNZ had previously developed a Microsoft Excel-based LCOE model specifically for calculating the LCOE. This is published online as Annex B to the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a). The Model's flexibility allowed sensitivity scenarios to be undertaken against the key cost and technical assumptions outlined above. It has been used to produced low, medium, and high LCOE estimates based on the data inputs developed by Arup.

Arup's primary objective was to produce current central LCOE values (medium case) that reflect current costs and deployment trends. In addition, effective minima (low case) and maxima (high case) are presented by combining the relevant low and high data inputs which illustrates the uncertainty surrounding the LCOE figures. For this analysis, no adjustment to Capex or Opex based on future learning rates has been applied, as the primary objective is to present LCOE results based on current, up-to-date assumptions.

By using the collected cost and technical data, Arup generated the following:

- **Medium LCOE:** This estimate used the mean or median values for all costs and technical assumptions.
- **Low LCOE:** This estimate was based on the following combination of inputs:
  - The lowest values for predevelopment, construction, and operating expenditure.
  - The lowest value for predevelopment, construction, and operational time periods.
  - The highest net power output and net load factor.
  - The highest value of plant operating period.
- **High LCOE:** This estimate was based on the following combination of inputs:
  - The highest values for predevelopment, construction, and operating expenditure.
  - The highest value for predevelopment, construction, and operational time periods.
  - The lowest net power output and net load factor.
  - The lowest value of plant operating period.

LCOE estimates for each technology are presented at the end of their respective technology chapter, along with a comparison of this study's LCOE results and the assumptions detailed in the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a). An overall comparison across technologies with the published Generation Costs 2023 assumptions and Literature can be found in Chapter 6.

To ensure consistency, all costs were reported in 2023 prices, using the GDP deflator figures from December 2023 published by the ONS.

Additionally, Arup calculated hurdle rates based on factors such as cost of debt, debt ratio, cost of equity, and equity ratio, using BloombergNEF's 2023 2H values[9]. Note that for the low, medium, and high scenarios the hurdle rate was kept consistent (see Section 5 for details), therefore further sensitivity cases exist based on this financial metric and should be considered as required. This approach allowed Arup to assess the impact of changes in cost and technical assumptions on LCOE.

Arup notes these results may not reflect the final LCOE that DESNZ adopts; the LCOE derived in this report is a key component of the findings but are not the sole factor likely to be considered. In a separate report, *Hurdle Rate Estimates for Generation and Storage Technologies (unpublished)*, DESNZ intends to provide an updated view on hurdle rates in the industry (DESNZ, 2023c).

3.8 Other costs and technical assumptions not included in LCOE

In addition to the direct costs considered in the LCOE calculation, there are several other factors that impact the overall economics of renewable energy projects. Arup gathered the following information through a questionnaire:

- Decommissioning cost: This cost pertains to dismantling and removing infrastructure at the end of the farm's operational life. It includes disposal and recycling expenses, net of earnings from the sale of scrap. This is not included within the DESNZ LCOE calculation tool used and has therefore been excluded from the LCOE calculations.
- Land Costs: These are the expenses related to acquiring or renting land / seabed for renewable energy infrastructure development and operation. It is important to note that land costs and seabed option and/or lease fees are not included in the Opex used within the LCOE calculations.
- Property and Business Rates as well as other Taxes.
- Wake Loss: Wake losses are caused by upwind turbines from within the project ("internal") or from neighbouring projects ("external"), resulting in reduced wind speeds and, therefore, energy production.
- Turbine Information: Technical parameters such as turbine size and hub height were also asked.
- Community benefit payments: These are voluntary contributions made by the developers of the solar or wind farm to support local communities.

Additionally, through the stakeholder questionnaire Arup asked specific questions concerning the following aspects:

- Differences in cost between offshore wind projects connecting to multi-purpose interconnectors or bootstraps versus those connecting to the onshore network via a radial connection.
- How short-run marginal costs (SRMC) influence developers' dispatch behaviour for renewable generators.
- Costs associated with turning down or self-curtailing when the renewable asset could otherwise be generating.
- Qualitative views from developers on how costs will change between 2035 and 2050.

3.9 Future outlook

3.9.1 Introduction

The future outlook of renewable energy costs is important when assessing the LCOE. The understanding of future cost trends can help policymakers and investors make informed decisions about energy infrastructure investments, subsidies, and long-term planning.

As part of this research, Arup asked stakeholders for their views on how costs have evolved since 2021, their expectations up to 2035, and from 2035 to 2050. Responses were largely qualitative in nature and covered predevelopment costs, construction costs, and operational costs.

As described in the Section 4, historical cost reductions experienced across the renewable energy industry do not reflect the evolving macro-economic situation since 2021, which has resulted in increased cost for renewable energy projects.

3.9.2 Overall methodology

The analysis is based on a combination of qualitative and quantitative data provided by stakeholders, supplemented with industry views and Arup's in-house expertise.

This report provides a variety of estimations of capital cost developments up to 2050. The analysis considers short- and long-term estimations and sets out potential scenarios (low, base, and high cases) to reflect the range of views observed.

Note that this methodology assesses the outlook of construction and operational costs. However, infrastructure cost (i.e. cost of grid connection infrastructure) is assumed to remain constant; this technology is mature and no further learning is anticipated. The focus of the future outlook analysis is therefore focussed on the generating technologies.

3.9.3 Future outlook Summary

The direction of future cost in the short-term is uncertain; although, based on a combination of stakeholder responses and recent experience, project costs are not expected to fall. In the short-term, costs could also increase from current levels. Therefore, a bottom-up method, wherein global and regional deployment drives cost reductions, would not capture the short-term expectations of cost. Arup has therefore separately assessed the short- and long-term cost fluctuations, based on a qualitative analysis of stakeholder responses. The result is a range of scenarios: low, base, and high. High and low can be considered sensitivity cases. More detail is provided in Section 5.6.

For fixed O&M, limited responses were received from stakeholders. As a result, Arup has used a combination of published industry views (BloombergNEF, 2024a) and inhouse knowledge to derive a fixed O&M cost adjustment curve for each technology.

3.10 Precision of data results

In this report, we have updated the costs and technical assumptions to facilitate the calculation of the Levelised Cost of Electricity (LCOE) for offshore wind projects. The values presented in the tables and figures are derived from detailed analyses and are intended to provide a clear and accurate representation of the data.[15]

Rounding and Precision

- **Rounding Methodology**: Costs are reported to one decimal place for values less than ten; values greater than ten are reported to the nearest integer. Technical assumptions have been rounded to the nearest integer.

[15] Results have been rounded to one decimal place, which does not reflect the certainty in the values and may not be adequate precision for certain purposes.

- **Exceptions**: Operating expenditure, capacity factors, and hurdle rates retain one decimal place as these are metrics to which the LCOE is highly sensitive. LCOE itself is reported to one decimal place.
- **Underlying Data**: The unaltered figures are available in the underlying spreadsheets. These should be used for precise calculations and analyses.
- **Interpretation of Results**: The rounded values are intended to provide a general understanding of the data trends and should be interpreted with an awareness of their precision and uncertainty. The precision that the results are reported to does not necessarily represent the precision for which the results can be confidently used but instead reflects the numerical analysis of the survey results. Section 3.5 of this report provides further details on data confidence, uncertainty and limitations of the results.

By adopting this approach, we aim to balance the need for clarity in presentation with the accuracy required for detailed analysis.

4. Literature review

This literature review sought to provide an overview of key developments in the LCOE of offshore wind over the last five years, paying particular attention to the recent price shocks which have impacted LCOE trends. The information gathered was used to inform the data assessment framework, assess stakeholder responses, and to benchmark Arup's LCOE calculations and underlying assumptions.

The impact of recent price increases has varied per geography, but. in general, wind developers, particularly offshore, are still encountering inflated prices and increasing LCOEs (BloombergNEF, 2024a; IEA, 2023a,b; IRENA, 2023; Lazard, 2024).

4.1 Summary

The review considered key literature from the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), Bloomberg New Energy Finance (BloombergNEF), and Lazard. The IEA and IRENA have provided views up until 2022 but have not yet updated their findings to capture developments in 2023 and 2024, so BloombergNEF and Lazard have been used to provide a more recent view.

The *IEA Renewable Energy Market Update* (IEA, 2023a) published in June 2023 analyses trends in renewable energy markets, including how the energy crisis, market dynamics, and financing will impact the LCOE of renewables. The report covers market developments up until April 2022, with forecasts for 2023 and 2024, and provides insights on a global and EU basis.

The International Energy Agency (IEA, 2023b) *World Energy Outlook 2023* builds on the Renewable Energy Market Update report and examines global energy trends more broadly, offering insights into future energy supply and demand. The 2023 edition focuses on the effects of geopolitical tensions, particularly the energy crisis following the Russian invasion of Ukraine, and how this has impacted market dynamics and project economics. The report focuses on the market in 2022 and developments up to 2030 and 2050, providing insights on a global and EU basis.

The International Renewable Energy Agency (IRENA) *Renewable Power Generation Costs in 2023* analyses global trends in renewable energy costs up to the end of 2022 (IRENA, 2023). The report considers the LCOE of renewable technologies and the economics of renewable deployment. The report has a global focus but also provides UK-specific data.

The *Lazard Levelized Cost of Energy+* is a US-focused report which analyses the levelised cost of energy for renewables against conventional technologies and considers the impact of macro-economic pressure on the build-out of renewables, providing a view up to 2024 (Lazard, 2024).

Bloomberg New Energy Finance (BloombergNEF) *Historic LCOE Benchmarks* and the *LCOE 2H 2023 Data Viewer* have been used to inform our understanding of trends in LCOE and provide insights on a global and UK scale (BloombergNEF 2023a, 2024a).

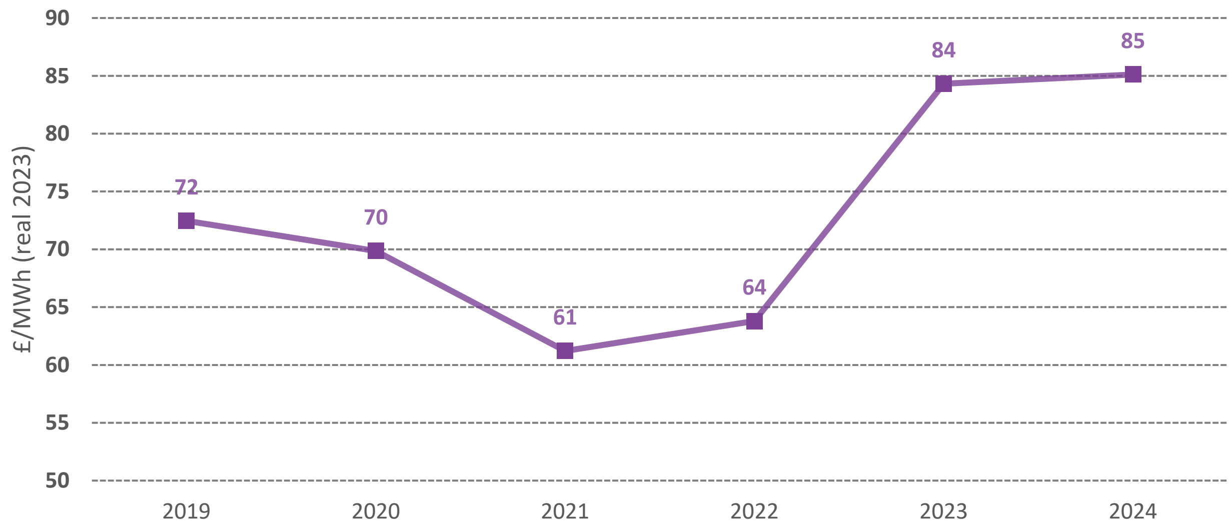
In addition to this, we have reviewed BloombergNEF reports including *2H 2023 LCOE Update: An uneven recovery* (BloombergNEF, 2023b), and *Solar Supply Chain Index* (BloombergNEF, 2024c). These reports provide insight on renewables deployment, LCOE trends, commodity prices and installation costs and provide both global and UK insights.

4.2 Historical trends

Offshore wind LCOE has followed a downward trend since 2010, falling 59% globally and 71% in the UK from 2010 to 2022 (IRENA, 2023). This decrease was driven by larger turbines, increased capacity factors, and technological advancements contributing to more efficient site design and reduced O&M costs. However, there is significant regional variability in offshore wind LCOEs. Recent commodity price volatility, including high steel prices, has particularly impacted the price of turbines in the UK and Europe, where developers are facing stubbornly high costs, leading to increased LCOEs.

The chart below shows a blended average of offshore wind LCOE data from the key literature over the period 2019-2024. Where provided in the literature, Arup has taken UK figures, and where these are not present Arup has taken global figures to create a blended average. The LCOE of offshore wind began to trend upwards from 2021 to 2022, with a more significant uplift in 2023. Forecast figures for 2024 show that offshore wind is still facing upward pressures on LCOE, but the scale of the uplift has decreased. The drivers behind these trends are explored in the following subsections.

Figure 3: Blended Average of Offshore Wind LCOE from 2019 to 2024[16] (2023 real prices)



4.3 Commodities

Commodity price rises —such as those noted in Arup's (2025) analysis of onshore wind—have also applied to offshore wind, with commodity prices significantly impacting the cost of wind turbines. Offshore wind is, however, more severely impacted due to the larger quantities of steel and copper utilised for larger offshore wind turbines, offshore wind foundation structures and high voltage inter-array cables. Combined, the wind turbine, foundation structure, and inter-array cables typically comprise 71% of total capex.

4.4 Capex

Offshore wind developers have higher total installed costs compared to onshore wind farms due to their location in the marine environment, which drives up installation, operating, planning, and project development costs. These inherently high total installation costs and significant inflation in recent years have placed notable pressure on the offshore wind sector.

Total installed costs for offshore wind decreased 23 % between 2010 and 2022 in the UK, driven by technology advancements including increased turbine size and design standardisation, economies of scale, supply chain improvements, and advanced logistics including the introduction of specialised vessels (IRENA, 2023). Turbine supply, transportation and installation form around 33-43% of the project costs for offshore wind (IRENA, 2023). The offshore sector has also been impacted by increased turbine prices following rises in the price of raw materials, such as steel, and supply chain disruption following the pandemic. These issues were exacerbated in 2022 following the Russian invasion of Ukraine. It is expected that turbine prices will remain elevated in 2024 with uncertainty remaining over turbine prices in the long term.

Companies across the offshore wind supply chain have experienced falling earnings before interest, taxes, depreciation, and amortisation (EBITDA) margins since 2015. According to van Doesburg (2023), the terms and conditions attached to new renewable energy projects, particularly in the offshore wind sector, have become overly complex and burdensome. This complexity is discouraging both investors and developers

[16] Note that literature sources did not consistently specify the years their LCOE results correspond to.

from moving forward, contributing to a stagnation in the market. As a result, the offshore segment is no longer functioning effectively, leading to an uneven and unsustainable distribution of profits across the value chain (Steitz, Jacobsen, & Gronholt-Pedersen, 2024). Although other factors have impacted the profitability across the supply chain such as increased competition and technology advancements. Developers, who have historically benefited from declining costs, have been facing lower-than-projected returns in the face of these rising supply chain and commodity costs, which has led to project delays and cancellations in the US and UK (Wood Mackenzie, 2023).

In addition, the offshore sector is also more impacted by logistics. Turbine installation vessel rates have increased since 2020 due to a shortage of specialist installation and jack-up vessels. It is expected that demand for these vessels will grow by up to 26% (4C Offshore, 2024) as these are also needed for maintenance, such as the replacement of key components.

There may also be a shortage of foundation installation vessels from 2028-2035 (4C Offshore, 2024) due to the continued drive for the installation of turbines in deeper waters. Deep water foundations generally have greater weight than their shallow water counterparts, which limits the number of vessels capable of installation.

4.5 Cost of capital

The rising cost of capital faced by developers has slowed down the number of new projects and has led to postponements of projects as well as asset write downs. A combination of rising inflation, higher interest rates, supply chain disruptions, and labour shortages has led to an estimated 4% increase in the cost of capital for renewable developers since early 2021 (Cornwall Insight, 2023).

The consequences of the higher cost of capital have already been seen on the offshore wind market. For instance, the developer of Norfolk Boreas has decided to stop the development of the offshore wind project stating that that the higher inflation and capital costs have made it too challenging to proceed with an investment decision. However, the development of the project has since resumed.

Since 2022, the offshore wind market has experienced several asset write-downs and declines in equity value (Timera Energy, 2023). Multiple European developers have also recorded impairments on their U.S.-based offshore wind projects, including Ocean Wind 1 and 2, largely due to supply chain disruptions, rising interest rates, and the absence of new tax incentives.

The trajectory of the cost of capital remains uncertain. While some stabilization may occur over the medium to long term, in the short term it is expected to remain elevated. As a result, this will continue to exert upward pressure on the LCOE for offshore wind, potentially slowing deployment unless offset by policy support or increases in subsidy pricing.

4.6 Technology advancements

Offshore wind turbines have significantly increased in scale since 2018, with modern turbines reaching capacities of >15MW compared to around 8MW in 2018. This has been made possible via significant technological and design advancements, allowing turbines to be built with much longer blades and with greater hub heights.

As offshore wind turbine scale has increased, so has the scale of the supporting substructures. XXL monopoles have diameters up to c.10m and facilitate access to deeper waters. This has allowed offshore wind farms to be placed further from shore, leading to higher yields.

Offshore wind capacity factors vary significantly based on location, technology, configuration, and O&M strategy. The global weighted average capacity factor of newly commissioned offshore wind projects increased from 38 to 42% from 2010 to 2022, whilst the UK reached 49% in 2022 (IRENA, 2023).

4.7 Operations and maintenance costs

Offshore O&M costs are higher than those of onshore wind due to the higher cost of accessing the site, contributing to 16-25% of LCOE, but are partially offset by the increased capacity factors which can be achieved offshore (IRENA, 2023). The use of performance data and predictive maintenance programs which are designed to implement solutions before failures occur have also historically driven down O&M costs. Lazard forecasts a 9% increase in O&M costs between 2023 and 2024 (Lazard, 2024); however, the downward trend is expected to resume, falling on average 2.5% per year up to 2030 (BloombergNEF, 2024a).

4.8 Conclusion

Historical reductions in offshore wind LCOE have been driven largely by increased turbine sizes, leading to increased energy yield. However, the offshore wind industry is still facing pressure from commodity price rises, higher capital costs, supply chain issues, and the challenges associated with developing projects in the marine environment. This has led to an increase in LCOE since 2022 which has been sustained into 2024. Offshore wind is highly sensitive to changes in commodity prices and the cost of capital, which places uncertainty over the LCOE trend in the short term.

Similarly, literature is showing that for offshore wind the return to pre-pandemic levels and the resumption of downward trends will depend largely on when the cost of capital, supply chain issues, and commodity prices stabilise.

5. Results and Analysis

5.1 Introduction

As of 2024, the UK has approximately 14.7 GW of installed offshore wind capacity (DESNZ, 2024), with an additional 3.9 GW under construction (RenewableUK, 2024).

Note that Arup collected stakeholder responses in April 2024, prior to the AR6 results being published.

5.2 Data collection and analysis

Data for our offshore wind energy analysis was collected from renewable energy project developers, an outreach to trade associations (to assist in connecting us to developers) and to technology manufacturers. In total, we received responses from six developers, providing 10 fixed-bottom offshore wind project data points, from which six of the offshore wind projects had commercial operations dates that would classify them as having "current" costs. The 10 data points represented a total installed capacity of 11,760 MW across offshore wind projects at various stages of development, including operational, under construction, and planned projects. Notably, seven were located in England and three in Scotland. Developers reported that turbine models for these projects range in capacity from 15 MW to 18 MW.

This study focused exclusively on fixed-bottom offshore wind projects. This decision was made due to the recent study on cost and technical assumptions for floating offshore wind conducted by Frazer Nash in 2023 (Frazer-Nash Consultancy, 2023). Consequently, three floating wind projects that were identified during data collection were excluded from the analysis.

Based on the data selection criteria outlined in Chapter 3, the data points were filtered to include only those that were robust, representative, and current. For cost analysis, only data points identified as current costs, as defined in Subsection 3.3.5, were selected for the analysis. For offshore wind projects, Arup considered current values to be those from projects with CODs ranging from 2028 to 2032. Four projects were excluded from the cost analysis due to the projects indicating COD earlier than 2028. As explained in Section 3.3. this is because, in this study, it is assumed that the associated costs have been established prior to 2023-24 and therefore cannot be considered “current”.

Only ten offshore wind responses were received. This number was reduced during the data validation exercise to ensure only “current costs” were considered for the assessment of Capex and Opex (please refer to Subsection 3.3.5 for more detail). Consequently, it would only require a small number of respondents to be unrepresentative of the population in order to skew results. This introduced a high risk of bias in the offshore wind results.

This filtered sample also exhibited a prevalence of jacket foundations, deep water, and HVDC transmission systems, which may have introduced bias, skewing average Capex upward, particularly compared to previous years. Furthermore, some responses relate to “generic” or “exemplar” projects. It is possible that theoretical projects such as these will not capture potential costs as reliably as defined projects, increasing uncertainty in the results.

Whilst factors such as water depth, distance from port and onshore grid connection point, and transmission system also affect Opex, the implications for Capex are more significant.

To understand whether bias had been introduced into the offshore wind results, Arup investigated the site-specific characteristics, assessing across Capex categories. Arup noted the following considerations as a result of this investigation:

- Two of the responses related to “generic” or “exemplar” projects. It is possible that theoretical projects such as these will not capture potential costs as reliably as concrete projects.

- Within this filtered sample of six projects, half of the wind farms utilised jacket foundations. These are typically a more expensive solution than monopiles, which have historically been the more popular choice.

- Similarly, half of the wind farms in the filtered sample were located in deep water (~60 metres). Deeper waters coincide with greater engineering complexity and material requirements and in turn, in all likelihood, greater Capex.

- The filtered sample also included a mix of HVAC and HVDC projects. HVDC transmission systems are generally more expensive than their HVAC counterparts, with the benefit of lower transmission losses over large distances. Grid connection distances ranged from 30km to 160km with an average of c.85km, indicating long distances from the project to grid connection point.

- Only England and Scotland were represented within this filtered sample. This means the findings do not account for potential cost variations specific to offshore wind farms in Welsh waters.

Connection and Use of System charges (TNUoS) for offshore wind are location-specific and the responses represent a broad range of results. The uncertainties surrounding the approach to future UoS charging regime also increases uncertainty of how this should be considered. The prevalence of jacket foundations, deep water, and HVDC transmission systems in the filtered sample could have resulted in increased Capex, particularly when compared to analysis carried out in previous years. However, as potential nearshore sites become less available and developers resort to deeper and more distant locations, these site characteristics are becoming increasingly common. Nevertheless, Arup remained cognisant of potential bias and the influence of site-specific characteristics on a project's LCOE. This was therefore investigated and addressed through the mitigants discussed in Subsections 3.5.2 and 3.5.3, ultimately resulting in a range of low, medium, and high sensitivities, reflecting the uncertainty in the findings.

To ensure the accuracy of the LCOE results, all cost and technical assumptions were compared against internal and externally published benchmarks. Arup's internal benchmark consisted of 22 projects located across the United Kingdom and other relevant offshore wind markets (including 10 recent projects in the UK). For external benchmarks, we primarily referenced the BloombergNEF and Lazard LCOE, cost, and technical assumptions for 2023 (BloombergNEF, 2024a) (Lazard, 2024), applying consistent FX and inflation factors to enable fair comparison[17]. Lastly, internal experts reviewed the final low, medium, and high, values to ensure they were in accordance with expectations.

For the medium value of cost or technical assumptions, either the mean or median of the dataset was used. The decision on which to use depended on the total number of data points available for the analysis. If the dataset contained fewer than ten data points, the mean was calculated as the central value. For larger datasets, the median was used, except in the predevelopment period for offshore wind farms, where an expert believed that the median should be picked as it was more aligned with their knowledge.

Regarding high and low values, Arup calculated the 5th and 95th percentiles of cost figures based on the survey responses. Using percentiles was necessary to anonymise the cost data provided by the developers. However, for time periods and other technical assumptions, Arup chose not to apply a 5th or 95th percentile because these are less easily identifiable metrics than cost; instead, the minimum and maximum values were used. This comprehensive approach ensured the validity and reliability of the data, providing a solid foundation for the subsequent analysis.

5.3 Cost and technical assumptions breakdown

5.3.1 Predevelopment expenditure

As indicated in Chapter 3, predevelopment costs refer to the expenses incurred up to reaching FID, before the construction of the offshore wind farm begins.

[17] It is important to note that approach to LCOE calculations are not universal; costs such as the handling of taxes, subsidies, insurance, and other items may be included by some organisations and excluded by others.

Through the stakeholder questionnaire, Arup requested total predevelopment costs, as well as the breakdown of i) pre-licensing costs, ii) technical and design costs, as well as iii) regulatory, licensing, and public inquiry costs, each as separate classifications. It was decided to use the total predevelopment cost for the subsequent analysis due to the larger number of data points in this category (9 data points) compared to the subcategories (one data point in the first, three in the second and two in the third). Utilising the total predevelopment costs rather than considering subcategories ensured all relevant costs were included and a more robust assumption would ultimately be derived.

Following the application of the selection criteria, five data points remained, from which a medium predevelopment cost (in 2023 real prices) was calculated as £216/kW, with low and high costs at £104/kW and £308/kW, respectively. One data point was disregarded because the developer indicated it included seabed lease option fees but did not provide the proportion needed for Arup to deduct these from the predevelopment expenditure. Therefore, to remain consistent with the definition of predevelopment expenditure in this study, this data point was removed.

It is important to note that predevelopment costs are expected to vary significantly depending on the site-specific conditions, planning hurdles, and requirement for appeals.

Table 10: Current predevelopment costs 2023-2024, (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Predevelopment cost	9	5	104	216	308

5.3.1 Predevelopment timings

After evaluating the provided data using the methodology detailed in Chapter 3, we selected three data points to estimate the total predevelopment period, which ranged from 7 to 15 years, with a median value of 7 years. In this analysis, we considered both the mean and median; however, Arup opted to use the median rather than the mean, even though fewer than 10 data points were available. This decision was driven by Arup's subject matter experts, who determined that the median of 7 years better aligned with typical industry experience and that the upper end of 15 years could be expected when awaiting a prolonged period for a grid connection to the national grid, or when a project is held up by specific planning hurdles such as public enquiry.

To incorporate predevelopment costs into the LCOE calculation, we estimated annual phasing based on low, medium, and high values from the predevelopment periods as described by developers. There were limited responses relating to the phasing of the costs over the predevelopment period. Therefore, in the absence of detail for the annual phasing of predevelopment costs, we used the low, medium, and high values for the time period of the chosen scenario with the costs evenly split.

The phasing of costs for each scenario is explained below:

- **Low Scenario**: Costs spread evenly across the first six years, with the remaining costs allocated to the seventh year (15.4% in the first six years and 7.7% in the final seventh year).
- **Medium Scenario**: Costs spread evenly across seven years (14.3% per year).
- **High Scenario**: Costs spread evenly across 15 years (6.7% per year).

Table 11: Predevelopment periods, years

Item	Total data points	Data points used	Low	Medium	High
Predevelopment period	4	3	7	7	15

5.3.2 Capital expenditure

5.3.2.1 Construction cost

Construction costs for an offshore wind farm include the costs associated with the supply and installation of wind turbines, foundations, array cables, as well as site preparation. For offshore wind this category does not include the costs of the offshore transmission export system, the OFTO (See Subsection 3.6.1.2 for further details).

The construction costs exclude land expenses, seabed lease costs, property and business rates, tax costs, rental fees, and community benefit payments, as noted in Subsection 3.6.1.2. For offshore wind projects, the construction costs (excluding OFTO costs) were derived from the total Capex provided by stakeholders with a proportion removed which was defined as "Infrastructure" (which as defined by stakeholder responses this is assumed to be the costs associated with the grid connection, substations, and other OFTO-related infrastructure, with all other cost in the total Capex)[18]. From assessment of stakeholder responses, our findings indicate that construction costs constitute 75% of the total capital expenditure, with the remaining 25% attributed to infrastructure costs. This proportion was derived from the responses received, reflecting the average distribution observed in the assessed projects, and is in line with Arup expectations.

The capital costs include contingency; however, specific values were not always provided by survey respondents.

Following the application of the selection criteria, six data points remained, from which a medium capital cost was calculated as £2,823/kW, with low and high costs at £2,415/kW and £3,101/kW, respectively.[19]

While Arup's internal benchmarks and literature review largely aligned with the reported values, one high-cost outlier presented by a respondent marginally exceeded the upper end of Arup benchmarks. On review, given that the data point only marginally exceeded the upper end by <1% and that it sat well within the upper end of literature benchmarks, it was decided not to exclude this data point based on the benchmark comparison alone. Excluding this high data point would have resulted in a medium cost of £2,761.4/kW.

Table 12: Current construction costs 2023-2024, (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Capital cost	9	6	2,415	2,823	3,101

5.3.2.2 Capital timings

After evaluating the provided data against the methodology described in Chapter 3, we selected six data points to determine the total construction period, which ranged from 4 to 5 years (with a mean value of 5 years). These timelines correspond to projects ranging from 900 to 1500 MW (average 1195MW) of installed capacity. The resulting range of timescales represents large scale offshore wind projects, most likely built across different phases of construction. The construction timescales are higher than previous assumptions published in the2023 Electricity generation costs report from DESNZ (DESNZ, 2023a).

Similarly to the approach for predevelopment costs, incorporating construction costs into the LCOE calculation required us to project annual cost phasing. These projections were based on the low, medium and high construction durations reported by developers. The data on cost phasing throughout the construction stage was limited. To maintain consistency with previous methodology, and in the absence of detail for the annual phasing of capital costs, we adopted a linear approach for projecting costs over the low, medium, and high construction durations of the chosen scenario.

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[18] Note that any profit associated with the sale of the OFTO is not considered in this analysis and could ultimately result in a reduction in overall LCOE for offshore wind projects.

[19] Note in this study the infrastructure costs are presented in £/kW units, whereas previous DESNZ cost generation studies considered this in £'000. Arup consider it is beneficial for scaling the infrastructure cost to refer to this in £/kW reflecting that the size and complexity of a project's transmission export system (OFTO) is related to the scale of a project's export capacity in kW.

The phasing of costs for each scenario is shown below:

- **Low Scenario**: Costs spread evenly across four years (25% per year).
- **Medium Scenario**: Costs spread evenly across the first four years, with the remaining costs allocated to the fifth year (21.6% in the first four years and 13.5% in the final fifth year).
- **High Scenario**: Costs spread evenly across the first five years, with the remaining costs allocated to the sixth year (19.0% in the first five years and 4.8% in the final sixth year).

Table 13: Construction periods (years)

Item	Total data points	Data points used	Low	Medium	High
Construction period	6	6	4	5	5

5.3.2.3 Infrastructure cost

Infrastructure costs include the expenses related to grid connection, substations, and other associated infrastructure elements. Similarly to the method used for calculating construction costs, the infrastructure cost was determined as a proportion of the total capital expenditure. This proportion, which averaged 25%, was derived from questionnaire responses regarding grid connection, substation, and transformer costs, as well as other infrastructure costs (see Subsection 5.3.2.1).

The medium infrastructure cost was calculated to be £937.0/kW, with low and high costs calculated at £801.7/kW and £1,029.5/kW, respectively.

It is important to note that infrastructure costs for offshore wind should not be included in the LCOE calculations, as they pertain to Offshore Transmission Owner costs (OFTO). These costs are subsequently reimbursed to the developer through the OFTO regime and covered by the Use of System Charges paid by the generator.

Table 14: Current infrastructure costs 2023-2024 (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Infrastructure costs	9	6	801	937	1,030

5.3.3 Operating expenditure

Operating costs refer to the ongoing expenses associated with the day-to-day operation of an offshore wind farm. These costs exclude land expenses, seabed lease costs, property and business rates, tax costs, rental fees, and community benefit payments, as noted in Subsection 3.6.1.3. To align with the DESNZ LCOE methodology, Arup divided the cost forecast into three categories: O&M, insurance, and connection and UoS charges.

5.3.3.1 Operations and maintenance

O&M costs for an offshore wind farm include all maintenance, logistics, and monitoring expenses in order to maximise production, maintain asset integrity, and safely operate the generating assets. These expenses typically include labour, vessels, remote monitoring, maintenance activities, purchase of spare parts, and on-site inspections.

Operations and maintenance costs are divided into two main categories: fixed and variable O&M. As part of the stakeholder questionnaire, Arup requested fixed O&M and variable O&M as separate classifications. However, due to the limited data received, with only one fixed and one variable O&M data point provided by developers, it was decided to calculate O&M as a proportion of total Opex received from stakeholders (12 data points), with a proportion allocated specifically to O&M. This proportion was derived from the Electricity Generation Costs 2023 report when excluding TNUoS from the total.

After applying the selection criteria, six data points remained, from which a medium O&M cost (in 2023 real prices) was calculated as £46.5k/MW/a, with low and high costs at £30.5k/MW/a and £64.6k/MW/a, respectively[20].

Since the latest DESNZ report (DESNZ, 2023a), connection charges and other aspects of Opex could have changed. Therefore, taking a proportion consistent with the last research may not give a totally accurate result. This introduces a level of uncertainty in how the O&M portion of total Opex has been derived. To mitigate this Arup carried out benchmark analysis and received input from subject matter experts and the resulting low, medium and high values were well-aligned with fixed O&M cost benchmarks from industry literature and internal Arup benchmarks, which provides some comfort in this approach.

Table 15: Current O&M costs 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
O&M costs	10	6	30.5	46.5	64.6

5.3.3.2 Insurance

Insurance for an offshore wind farm is designed to protect against the various risks associated with operation and maintenance. According to DNV, 80% of insurance claims in offshore wind are related to subsea cable failures (DNV, 2021). The medium insurance cost (in 2023 real prices) was calculated as £8.6k/MW/a, with low and high costs at £8.0k/MW/a and £9.7k/MW/a, respectively. This small range could be explained by the comparable sizes of the projects where responses were received, all of which were around 1 GW in capacity.

Table 16: Current insurance costs 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
Insurance costs	5	4	8.0	8.6	9.7

5.3.3.3 Connection and UoS charges

Network Use of System charges are the costs of connecting to and using the distribution and transmission network. For offshore wind, the UoS charge covers the cost of constructing, operating, and maintaining the transmission assets required to connect to the onshore transmission system. This includes both local and wider TNUoS charges, calculated on a k£/MW per annum basis.

After applying the selection criteria, a dataset of five data points remained, from which a medium Connection and UoS Charge was calculated as £83.4k/MW/a, with low and high costs at £35.3k/MW/a and £132.9k/MW/a, respectively. All five data points corresponded to TNUoS charges.

Arup cross-referenced the results with the National Grid's Five-Year View of TNUoS Tariffs for 2025/26 to 2029/30 to validate the responses. All responses were aligned with the National Grid forecast.

It is worth mentioning that connection and UoS charges can vary greatly depending on site-specific conditions and location, leading to a wide range of costs. Stakeholders emphasised that the TNUoS charges

[20] TheElectricity generation costs report from DESNZ (DESNZ, 2023a) presented O&M separately as fixed and variable costs. In this analysis it was not possible to derive this differentiation. To align with Arup internal benchmarks and approaches seen in industry literature, Arup determined the best approach was to include a single "Fixed" O&M cost only.

for offshore wind farms are highly sensitive to the regulatory framework for calculating charges and this may cause costs to fluctuate greatly in future.

Table 17: Current connection and UoS charges 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
Connection and UoS charges	9	5	35.3	83.4	132.9

5.4 Technical assumptions

Based on the data received from developers, Arup derived up-to-date key technical assumptions, crucial for determining the LCOE. The following provides a summary of the observations.

5.4.1 Gross power

Gross power for an offshore wind farm refers to the total electrical power output that the wind farm is capable of producing under ideal conditions, without accounting for losses due to the electrical conversion system, inefficiencies, or other factors.

This study defined the medium-sized offshore wind site as having a gross capacity of 1,297 MW, with a range from 900 MW to 2,250 MW.

Table 18: Gross power (MW)

Item	Total data points	Data points used	Low	Medium	High
Gross Power	10	9	900	1,297	2,250

5.4.2 Load factor

Load factors for an offshore wind farm can be presented as either gross load factor or net load factor, see Subsection 3.6.1 for more details. The gross load factor reflects the estimated energy output that the wind farm could produce under ideal conditions, without accounting for losses such as system availability (Wind Turbine Generator or WTG, Balance of Plant or BoP, and grid), wake losses (internal and external), electrical system losses, turbine performance losses, degradation, and other secondary loss factors. Stakeholders provided both gross and net loss factors, which were assessed. However, since the net load factor accounts for all applicable losses, this should be used to calculate net energy production for the LCOE analysis.

Arup calculated a net load factor of 50.5%, with high and low values of 46.0% and 56.1%, respectively. Arup's benchmarks for UK projects indicate a load factor of 49%, which closely aligns with the medium figure.

Table 19: Net load factor (%)

Item	Total data points	Data points used	Low	Medium	High
Net Load Factor	10	9	46.0%	50.5%	56.1%

5.4.3 Plant operating period

The operating lifetime of an offshore wind plant refers to the period during which the plant is expected to be functional and generate electricity. Based on the responses received from stakeholders, Arup estimated the average operating lifetime of an offshore wind site to be 35.0 years. Notably, the minimum and maximum values were also 35.0 years, as almost all the projects received had assumed the same operating lifetime. This is in line with internal benchmarks and trends Arup has seen in recent offshore wind business case.

Table 20: Operating lifetime (years)

Item	Total data points	Data points used	Low	Medium	High
Operating lifetime	9	8	35	35	35

5.5 Summary of results

5.5.1 Costs and technical assumptions

We have summarised the main costs and technical assumptions for offshore wind projects in this study, including the low, medium, and high cases of each category in the table below.

Table 21: Summary of 2023-2024 current costs and technical assumptions for offshore wind in this study

Category	Unit	Offshore Wind		
		Low	**Medium**	**High**
Costs				
Pre Development	£/kW	104	216	308
Capital Costs During Construction	£/kW	2,415	2,823	3,101
Infrastructure Costs[21]	£/kW	802	937	1,030
Total Capex	£/kW	3,321	3,976	4,439
Insurance	k£/MW/a	8.0	8.6	9.7
Connection And UoS Charges	k£/MW/a	35.3	83.4	132.9
O&M	k£/MW/a	30.5	46.5	64.6
Total Opex	k£/MW/a	73.7	138.5	207.2
Technical assumptions				
Net load factor	%	46.0%	50.5%	56.1%
Operating lifetime	years	35	35	35
Additional assumptions				
Hurdle Rate[9]	%	6.2%	6.2%	6.2%
Predevelopment timescale	years	6	7	15
Construction timescale	years	4	5	5

5.5.2 LCOE results

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. As described in Section 3.7. LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore,

[21] For offshore wind, there is a different arrangement for the capture and allocation of transmission cost. Offshore transmission owner (OFTO) construction costs for the electricity transmission cable are excluded from the analysis as OFTO payments are made via the payment of local and wider TNUoS charges, which are included within the operating costs. This avoids double counting the cost of offshore transmission assets. Note that any profit associated with the sale of the OFTO is not considered in this analysis and could ultimately result in a reduction in overall LCOE for offshore wind projects.

it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

The results are shown in Table 22. These scenarios are designed to be indicative and to offer a range of LCOE estimates for comparison with current LCOE scenarios in industry literature. A comparison between this study's results, a blended average of the literature, and DESNZ current LCOE estimates is provided in Chapter 6.

Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Table 22: LCOE, based on current costs 2023-2024, (2023 real prices £/MWh)

Item	Hurdle rate (%)	Low	Medium	High
LCOE	6.2	55.4	88.5	124.0

5.6 Future outlook

For offshore wind, respondents indicated that cost reductions are challenging to achieve, and real price increases could continue if supply chain constraints and bottlenecks continue. Stakeholders also indicated that the key parties in the supply chain are showing less willingness to fix prices, exposing developers to increased variance in cost. One respondent noted the constant failure to meet deployment targets is leading to increased competition and that, without a corresponding investment in the supply chain, this may lead to further cost increases.

There were limited qualitative and quantitative views available on future cost reductions, leading to uncertainty in how to reflect cost reduction in the short- and long-term. Therefore, Arup has considered a range of scenarios (low, base, and high cases) to reflect different possible outcomes based on the small sample of quantitative responses. Stakeholders indicated that for the period 2030-2035, achieving cost reductions in real terms will be challenging therefore as a medium case no cost reductions are applied. Stakeholder responses indicated that from 2030 to 2035, an optimistic scenario could see cost reductions range between 5% and 10%. The reduction is based on an assumption that cost and inflationary pressures affecting the supply chain ease. However, they also indicated that costs could increase by up to 10% over the same time frame.

In an optimistic case, stakeholders indicated that cost could reduce by between 10% and 15% from 2035 to 2050, based on technology advancements such as innovations in manufacturing (advances in materials / manufacturing techniques), increased automation (further use of remote monitoring/drones/IoT, robotics and AI to reduce turbine downtime and overall enhance turbine performance) and larger wind turbines.

Stakeholders indicated that capital cost can be divided into the following subcomponents. The corresponding proportions are illustrated in the table below.

Table 23: Proportions for separate components in capital costs (offshore wind)

Component breakdown	Capex proportion
Turbine supply	35%
Turbine transportation & installation	3%
Foundation supply	16%
Foundation transportation & installation	8%
Cables (Inter-array) supply	3%
Cables (Inter-array) transportation & installation	1%
Cables (Export system/grid connections) supply	5%
Cables (Export system/grid connections) transportation & installation	2%
Offshore substation EPC	12%
Other Costs	15%

The main driver of historical cost reductions on a per MW basis have been physical scale (rotor size and hub height), installed generating capacity (MW), foundations, and efficiencies across the supply chain. The projects considered by stakeholders include turbines with an average size of 15 MW. The long-term expectation is that turbine sizes will continue to increase in scale, reaching between 20 and 22 MW. Current turbine scale (15-18MW) is reflected in the current assumed cost with capacities of c. 20MW considered for projects beyond 2032. It is considered that increases in turbine scale may impact future projects post-2030; however, the impact of the "learning curve" is not expected to be as dramatic as has been seen historically. The main reason for stable costs, as noted by stakeholders, is due to ongoing supply chain re-adjustment, i.e. turbine costs will not reduce until the OEMs have a period of profitability allowing costs to reduce. Limitations in vessel size for the transportation and installation were also noted as being a restriction on turbines increasing in size over the next 10 years. The lack of available vessels affects the commercial viability of larger turbines, leading to bottlenecks and increases in timescales and cost.

Stakeholders also note that early capex commitments are being increasingly required to maintain delivery schedules. This is due to the supply chain facing shortages and long lead times for components like WTGs, main electrical equipment, cables, foundations, vessels, as well as personnel.

It is not clear if the impact of Chinese WTG manufactures entering and capturing market share is factored into the views of stakeholders. Arup would expect the entry of Chinese manufacturers into the market to result in a large reduction in future wind turbine costs (potentially up to 40% lower), resulting in more aggressive cost adjustments in the future. Overall, with turbine supply costs representing a high proportion of capex (35%), a 40% reduction in turbine costs could result in a 14% reduction in total cost. At this point in time, there is uncertainty around Chinese turbines' technical performance and cost reduction, and therefore their impact on LCOE.

5.6.1 Resulting future price adjustments

In terms of each scenario (low, base, and high case), the capital cost forecast is estimated based on ranges provided via the stakeholder survey. For offshore wind, stakeholders indicated that between 2030 and 2035, the reduction in capital cost could range between +10 and -10%, potentially reducing by 10 to 15% between 2035 to 2050.

Short-mid-term: The cost data provided by stakeholders reflect projects with COD dates of up to 2032. Therefore, in the medium case, Arup assumed that cost will be flat up to 2032. This is a simplified assumption and is based on the details provided by stakeholders and from the review of literature, reflecting the uncertainty of any material near-term reductions in cost. Regarding the future outlook, stakeholders indicated that capital costs are expected to remain unchanged across this period. Therefore, up to 2032, the cost adjustment has been set to 100%. High and low sensitivity cases have been taken as the upper (+10% by 2035) and lower range (-10% by 2035) presented by the respondents.

Long-term: By 2050, capital cost is expected to decrease on average by 12.5% (the midpoint between -10% and -15%), reducing to 87.5% of 2023 cost. High and low sensitivity cases have been taken as the upper and lower ranges provided by the respondents.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close[5]), unless stated otherwise. These years do not necessarily correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.[22]

Table 24: The capital cost forecast for three scenarios (offshore wind)

Scenario	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Low case	100.0%	98.3%	94.2%	90.0%	85.0%	75.0%
Medium case	100.0%	100.0%	100.0%	100.0%	95.8%	87.5%
High case	100.0%	101.7%	105.8%	110.0%	106.7%	100.0%

5.6.2 Fixed O&M

Limited responses have been received from stakeholders regarding future adjustment to offshore wind O&M costs.

Therefore, Arup has assessed the latest industry view (BloombergNEF, 2024a) and used inhouse knowledge to derive future fixed O&M cost adjustment curves ("learning rates") for offshore wind.

Table 25: The forecast fixed O&M cost (offshore wind)

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Fixed O&M projection	100.0%	94.5%	82.4%	73.9%	67.6%	59.2%

The percentage change in fixed O&M cost is calculated year-on-year. The fixed O&M cost is expected to decrease by an average of 2.3% per year until 2040. From 2040 to 2050, the reduction rate is projected to slow to an average of 1.3% annually. The fixed O&M cost curve for offshore wind is much steeper compared to other two technologies in the long-term as there are more areas of O&M where cost savings can be achieved.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), unless stated otherwise. These years do not necessarily correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.[22]

[22] For example, an offshore wind project securing costs in 2025 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), should apply 100% of the "current costs" (as defined above) for capital costs and 94.5% of the Fixed O&M costs. This project may not become operational for a number of years after securing the costs, following time taken to reach financial close and then for the site to be constructed. Another example could be a project securing costs in 2030 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close) where a 100% Capital Cost factor and 82.4% Fixed O&M cost factor should be applied through multiplication, to the "current costs" (as defined above) resulting in a lower capital and operating cost.

5.7 Comparison of previous and current costs, technical assumptions and LCOE results

In this section, Arup compared the costs and technical assumptions presented in DESNZ's Electricity Generation Costs 2023 report with the outcomes of our latest study.

5.7.1 Approach

The comparisons are based on medium cost values. Furthermore, Arup's calculations were based on £2023 real values, whereas the Electricity Generation Costs for 2023 were reported in £2021 real values. To align these figures, we adjusted them to 2023 values using the GDP deflator figures from December 2023 published by the Office for National Statistics.

The LCOE calculation incorporates Arup's current hurdle rate assumptions and is based on the latest current costs and technical assumptions. The hurdle rate, calculated by Arup and derived from the cost of debt and equity from industry literature for offshore wind, is 6.2%.

The table below provides a comparison between the new and old estimates for predevelopment, capital, and operating costs, as well as the technical assumptions necessary for the LCOE calculation. It is worth mentioning that although these costs and technical assumptions are current at time of the analysis, Arup selected the scenario from DESNZ's Electricity Generation Costs 2023 report that most closely matched our study parameters. For offshore wind, the projects analysed had CODs ranging from 2028 to 2032. Given that DESNZ provided scenarios for projects with commissioning years of 2025, 2030, 2035, and 2040, the 2030 scenario was deemed the most appropriate and relevant for this comparative analysis.

5.7.2 Results

Overall LCOE has increased by 102% compared to the previously presented DESNZ Electricity Generation Costs 2023 report. It should be noted that for the latest AR6 CfD auction round, certain evidence-based adjustments were made to the assumptions used by DESNZ in their energy modelling, such as increases to capital costs (DESNZ, 2023b). These adjustments are not reflected in the DESNZ 2023 Electricity Generation Costs report and are therefore not captured in this comparison.

This, to a certain extent, explains why the difference is high in this comparison, with a significant increase in total capex. When compared to the latest industry literature, the Arup results are better aligned, and we therefore consider the results to be representative of current assumptions. Arup's comparison against latest literature can be found in Section 6.1.

The changes in LCOE are driven by the following key factors:

- **Increased Capex:** overall total capex has increased by 88%. As noted above, this percentage change does not reflect the evidence-based adjustments made in recent DESNZ modelling[23]. As described in Section 4, the offshore wind industry has faced pressure from commodity price rises, higher capital costs, supply chain issues, and the challenges associated with developing projects in the marine environment. This has led to an increase in LCOE since 2022 which has been sustained into 2024 and therefore the large difference is not unexpected. In some of the sub-categories, the costs are shown to be reduced, for example in the predevelopment sub-category cost. A reason for these differences could be the varying approaches taken to deriving the allocation of these costs between studies. Additionally, there is a greater level of uncertainty in the offshore wind Capex results due to there being fewer responses for this technology. The technical characteristics of the sample of wind farms, which exhibited a prevalence of jacket foundations, deep water locations, and HVDC transmission systems, may have introduced bias, driving up cost estimates, particularly compared to previous years. Furthermore, some responses relate to "generic" or "exemplar" projects. It is possible that theoretical projects such as these will not capture potential costs as reliably as defined

[23] It should be noted that for the latest AR6 CfD auction round certain evidence-based adjustments were made to the assumptions used by DESNZ in its energy modelling, such as increases to capital costs (DESNZ, 2023b). These adjustments are not reflected in their latest Electricity Generation Costs report and are therefore not captured in this comparison.

projects, further increasing uncertainty in the results. The potential effects of bias were investigated and discussed in Section 3.5.

- **Reduced net load factor:** the updated net load factor (50.5%) is in line with Arup's expectations and is based on the net load factors provided by stakeholders. The Generation Costs 2023 study followed a different approach, calculating the gross load factor using technical performance and weather data, then reducing it by availability to derive a net load factor. The lower net load factor reported by stakeholders would increase the overall LCOE.
- **Plant operating period:** increasing the asset's operational life from 30 to 35 years has reduced the LCOE. This is in line with the latest typical assumptions for asset life made across industry and is supported by asset life extension analysis that Arup has carried out.
- **Insurance and Connection and Use of System Charges:** Arup's latest analysis has resulted in an increase in both insurance and UoS charges, which have led to a higher LCOE. Connection and Use of System charges (TNUoS) for offshore wind are location specific and responses represent a broad range of results. The uncertainties surrounding the approach to future UoS charging regime also increases uncertainty of how this should be considered.

As stated above, Arup has compared this study's medium results with those from DESNZ's Electricity Generation Costs 2023 medium results. This can be found in the table below.

Table 26: Offshore wind – Arup's key study results versus DESNZ's assumptions (DESNZ, 2023a) (2023 real prices)

Assumption	Unit	Arup (medium)	DESNZ projection for 2030	% Change
Technical				
Hurdle Rate	%	6.2%	6.3%	
Net Load Factor[24]	%	50.5%	65.0%	
Gross Power Output	MW	1,297	1,000	
Plant Operating Period	Years	35	30	
Predevelopment Period	Years	7	5	
Construction Period	Years	5	2	
Cost				
Predevelopment expenditure	£/kW	216	461	
Capital costs during construction	£/kW	2,823	1,576	
Infrastructure costs	£/kW	0[25]	72	
Total Capex (incl. predevelopment expenditure)	£/kW	3,039	2,109	44%
Insurance	k£/MW/a	8.6	3.3	
Connection and UoS charges	k£/MW/a	83.4	49.1	
Fixed O&M	k£/MW/a	46.5	47.4	
Variable O&M	£/MWh	0.0	1.1	
Total Opex	k£/MW/a	138.5	106.1[26]	31%
Total LCOE	**£/MWh**	**88.5**	**43.9**	**102%**

5.8 Other key findings

Arup gathered additional information that falls outside the scope of the LCOE calculations, on behalf of DESNZ. It is important to note that the same methodology employed above was used to calculate the low,

[24] Clarification: The comparison presented is based on two distinct methodologies. Arup's calculation of the net load factor includes all losses. In contrast, the previous report's average load factor (net of availability) does not encompass all losses, resulting in a lower figure. This distinction is essential for an accurate understanding of the data.

[25] For the purpose of comparison, the calculated infrastructure cost of £937/kW has been set to zero, as Arup assumes this relates entirely to OFTO infrastructure. In offshore wind, transmission assets are transferred to Offshore Transmission Owners (OFTOs), and the associated capital costs are recovered through TNUoS charges, which are included in operating costs. This avoids double counting.

[26] Total Opex was calculated by converting all components to a consistent unit.

medium, and high values of the findings in this section. A summary of these findings is presented in the following subsections.

5.8.1 Land costs

These costs encompass the expenses associated with leasing seabed areas from The Crown Estate or Crown Estate Scotland, which are necessary for the installation and operation of offshore wind turbines. The average of the six quantitative costs provided is £150.0k/MW/a. Additionally, one developer noted that these costs amounted to 2% of their revenue.

It is noted that, with the exception of one respondent, the predevelopment costs calculated above exclude seabed option fees, however the respondents did not provide their assumptions for this cost.

5.8.2 Property and business rates

The responses received varied too widely to allow for a clear understanding of the property and business rates experienced by developers.

5.8.3 Tax

Developers were also asked to provide any additional taxes they were required to pay. Only one response was received, noting that the corporation tax rate is 25%.

5.8.4 Decommissioning costs

Decommissioning costs involve the expenses related to safely dismantling and removing infrastructure of an offshore wind farm at the end of its operational life. Arup received nine responses regarding these costs, and after evaluating the information received based on the criteria outlined in Chapter 3, five data points were used to calculate an average decommissioning cost of £86k/MW, with a low cost of £59k/MW and a high cost of £140k/MW.

5.8.5 Short-run marginal cost

Short Run Marginal Cost is defined as the change of total cost when producing one more unit of energy (e.g. 1 MWh). In the short-term, the capacity of the energy system is fixed, the short-term marginal cost only includes the operating costs of the existing infrastructure, without any additional investment. Arup did not receive any responses regarding SRMC.

As with onshore wind, Arup’s view is that SRMCs do not impact the dispatch behaviour of offshore wind operators; however, it is influenced by curtailment or bids into the balancing or capacity market when those bids exceed revenue from CfD exports.

5.8.6 Self-curtailment

Self-curtailment is the intentional reduction of electricity generation by the wind farm itself. Arup did not receive any responses regarding self-curtailment.

Arup's view is that the cost of self-curtailment is a function of the offtake arrangements of projects and the projects’ participation in the balancing market. Given the various approaches to securing CfD, Power Purchase Agreements (PPA), or alternative routes to market, the approach to self-curtailment will vary between projects.

5.8.7 Availability profile

Availability in this context refers to the maximum potential time that a generation plant can produce electricity annually (energy based – i.e. the proportion of possible energy production). Based on the responses received, we calculated the minimum, maximum, median, and mean values of availability (%). For the medium case, the mean was selected as the number of data points was fewer than 10, as described in Section 3.4.

It is important to note that while an availability profile is being presented, it was not used to calculate LCOEs, as the Net Load Factor was utilised, which already accounts for the availability profile.

The average availability for an offshore wind project was calculated to be 95.9%, with minimum and maximum availabilities of 95.8% and 96.0%, respectively.

5.8.8 Community benefit payments

Community benefit packages are voluntary contributions made by offshore farm developers to support local communities. Arup did not receive any useful responses regarding these packages.

5.8.9 Wake loss

Wake losses occur when neighbouring wind turbines experience reduced energy yield due to the wake effect caused by other turbines. These can be interactions with turbines within the project or from neighbouring wind farms. According to the five questionnaire responses received, wake loss estimates range from 6% to 10%, with an average of 8% across the projects received. The wide variation is assumed to result from the site-specific nature of wake losses.

5.8.10 Bootstrap connection

As part of CfD AR7 consultation, DESNZ is testing emerging views that offshore wind farms connecting into bootstrap connections should be eligible for CfD contracts.

As part of the stakeholder engagement, developers were asked whether there would be any differences in costs between an offshore wind project connecting to a bootstrap compared to connecting to the onshore network via a radial connection. They were also asked to identify the elements of project costs that might differ and to estimate the scale of these costs.

A limited number of responses was received and no clear evidence of the impact on costs could be derived.

It was generally noted that radial connections for a single wind farm, as per the current regulatory framework, tend to have lower costs today, although these costs can vary depending on circuit length and capacity. Unlike with radial connections, the Transmission System Operator (TSO) designs and builds the bootstrap or multi-purpose interconnection system. These costs can be higher than those of radial connections, although they are dependent on a range factors.

A key issue identified is interface risk between the wind farm development and the construction of the offshore transmission system. If the bootstrap is operational before the wind farm is constructed, it can help mitigate this risk. Additionally, it was noted the length of the bootstrap determines the choice of export technology (HVAC or HVDC).

5.8.11 Multi-purpose interconnectors

Similarly, as part of CfD AR7 consultation, DESNZ is testing emerging views that offshore wind farms connecting via multi-purpose interconnectors (MPI) should be eligible for CfD contracts.

As part of the stakeholder engagement, developers were asked about potential cost differences between an offshore wind project connecting to a multi-purpose interconnector versus connecting to the onshore network via a radial connection. They were also asked to specify which elements of project costs might differ and the potential scale of these costs.

A limited number of responses were received and no clear evidence of the impact on costs could be derived. Furthermore, the literature reviewed did not include a description of how LCOE would be impacted by future MPI scenarios. It was also noted by one developer that no specific analysis has been conducted to date regarding these cost differences.

One respondent mentioned that a multi-purpose interconnector could be beneficial, but significant uncertainties remain, particularly concerning the OFTO TNUoS charges and the lack of clarity on the control aspects of commissioning.

6. Comparison of LCOE estimates

6.1 Approach

This section presents a comparison of the LCOE for offshore wind based on Arup's 2023-2024 cost and technical assumptions analysis to a blended average of LCOEs from global and UK literature and estimates from the Electricity Generation Costs 2023 report from DESNZ (DESNZ, 2023a). The comparison reveals variations across the different sources, highlighting recent trends and regional impacts on LCOE.

The available literature includes a range of sources (see Section 4.1), published between 2022 and June 2024, covering both global and regional views. To ensure a fair comparison, only sources from 2024 were used to calculate the blended average shown in the charts. It is worth noting, however, that whilst these sources were published in 2024, the CODs or FID dates of the underlying projects may differ from those used by Arup in this project.[27]

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. The hurdle rate is consistent across cases, which provides clarity on how changes in cost and technical assumptions affect the LCOE.

As described in Section 3.7, LCOE is highly sensitive to the underlying load factor, discount rate, and capital and operating cost assumptions. Therefore, in order to capture uncertainty, the standard approach is to consider a range of scenarios rather than a single point. The ranges presented in this report illustrate the potential variability in generation costs, demonstrating why the central case should not be interpreted as a definitive value. Arup suggests that, when considering generation costs, sensitivities should be assessed within this range, as the central case alone does not represent the full breadth of possible outcomes.[28]

6.2 Results

The chart below (Figure 4) presents a comparison of LCOE ranges from Arup's 2023-2024 cost and technical assumption analysis, the blended literature average, and DESNZ's 2023 estimates (DESNZ, 2023a).

For offshore wind, Arup's LCOE is 88.5 £/MWh, which is 4% higher than the blended literature average of 84.9 £/MWh. The Arup LCOE is 102% higher than DESNZ's estimate (DESNZ, 2023a) of 43.9 £/MWh.

This is the most significant difference seen across the technologies. It should be noted that for the latest AR6 CfD auction round, certain evidence-based adjustments were made to the assumptions used by DESNZ in its energy modelling, such as increases to capital costs (DESNZ, 2023b). These adjustments are not reflected in the Electricity generation costs 2023 report by DESNZ and are therefore not captured in this comparison.

This, to a certain extent, explains the magnitude of the difference, with a significant increase in total Capex. When compared to the latest industry literature, the Arup results are better aligned, and we therefore consider the results to be representative of current assumptions.

Refer to Section 5.7.2 for detail on the key drivers of change in LCOE.

Given that there is a significant difference in the LCOE derived from Arup 2023-2024 assumptions, the blended literature and the DESNZ 2023 estimates (DESNZ, 2023a), Arup carried out further analysis of the underlying responses to assess the data confidence, potential bias, and uncertainty. See sections 1.6 and 3.5 for more details.

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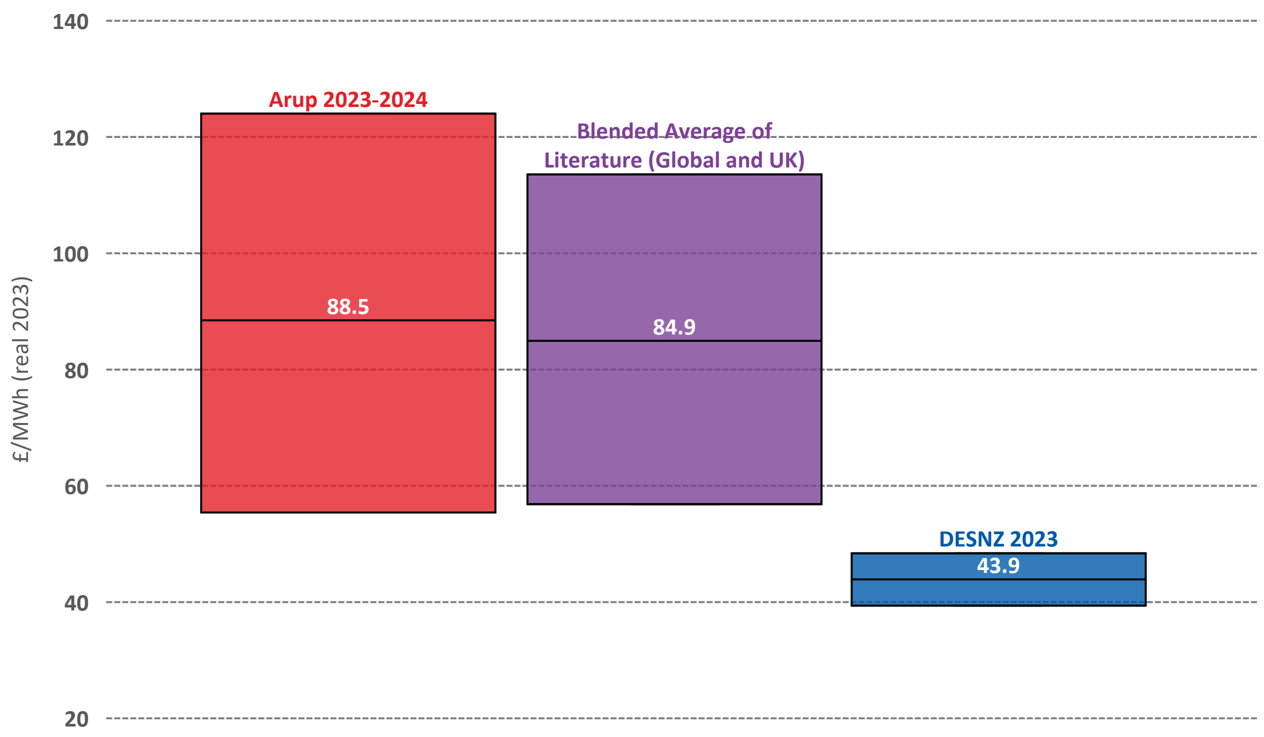
[27] Note that literature sources did not consistently specify the years their LCOE results correspond to.

[28] Arup also notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Figure 4: Offshore wind LCOE comparison across Arup 2023–2024, literature review, and DESNZ 2023 report



- The maximum line represents the High LCOE, the inner line represents the Medium LCOE, and the minimum line represents the Low LCOE. Refer to Section 3.7 for details on the constituents of these LCOEs.

7. Recommendations to future-proof

To future-proof the LCOE work between procurement cycles and developer surveys, Arup recommends that DESNZ implements an annual benchmarking process, ideally managed by an independent third-party expert. This process should involve reviewing key publications from organisations such as the International Energy Agency, International Renewable Energy Agency, BloombergNEF, and Lazard, focusing on Capex, Opex, load factors, and LCOE. The third-party should also use its internal expertise and knowledge of the latest industry trends to compare to the external industry benchmarks.

The third-party expert should have the relevant know-how to assess the evolution of costs since the previous benchmarking, the consistency of assessments carried out by external organisations, and how the 2024 DESNZ LCOE figures compare to the latest data. This annual desk-based research would provide a partial update on costs without the requirement to carry out regular stakeholder engagement. In Arup's view, there is still a requirement for periodic engagement with stakeholders; however, the frequency could be reduced if there is a robust approach to benchmarking, carried out by experts with access to the relevant data.

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Appendices

A.1 Questionnaire for developers

The following shows copies of the data collection survey sent to developers. This includes the questionnaire sent for onshore wind and solar that is covered more in Arup (2025).

Section A – Project Specific Information

	General project questions	Response		
Priority	**Renewable technology,** *please select technology*	*Please select*		
	Please specify whether the data provided below pertains to a newly established site or a site that has undergone full repowering*	*Please select*		
	Name or title of project	*Insert name*		
	Location of project *(e.g. England, Scotland, Wales)*, *please select*	*Please select*		
Priority	**Stage of project** *(Earlier than pre-development, pre-development, financial close, ready to build/under construction, operation start, operational)*	*Please select*		
Priority	**Operation start year** *(Expected or actual)*			
Priority	**Specify the size for which specific project costs are provided for, in MW(e) net (please provide net electrical capacity.)**			
	How is the land/seabed structured? *(E.g., lease, freehold, rented)*			
	What procurement / contracting strategy is in place? *(E.g., full engineering, procurement and construction contract, EPC wrap or individual sub-contracts)*			
	What is the approximate distance in km to the grid? Is the project connected to the electricity distribution or transmission grid?			
	Is the data provided below commercially confidential? *(Please indicate which aspects of the data are confidential and why.)* ***Important Note: All data will be held securely by Arup, anonymised, and treated as confidential.***			
	Cost Items	**Unit**	**Response**	**Comment**
	PLANT ASSUMPTIONS			
Priority	**Plant capacity MW(e) gross** *(Nameplate capacity of generating assets)*	[MWe]		
	Plant capacity MW(e) net *(Gross capacity minus all electrical system losses and parasitic loads)*	[MWe]		
	Grid Connection capacity *(What is the maximum export capacity at the grid entry point?)*	[MW]		
	CURRENCY ASSUMPTIONS	**Unit**	**Response**	**Comment**

	Currency	[£,$,€]	*Please select*	
	PRE-DEVELOPMENT COST *(Please note: this should exclude land costs, property and business rates, tax costs, rental and community benefit payments. These are requested separately in Additional Data section below.)*	**Unit**	**Response**	**Comment**
	For each cost entry, could you please specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What is the total Development expenditure (devex)** *e.g. costs incurred up to the point of reaching Final Investment Decision (FID)*			
	Pre-licensing cost *(E.g., development costs including planning, submission fees, survey costs etc.)*	[£]		
	Technical development cost *(Including design)*	[£]		
	Planning cost *(Including regulatory costs, licensing, public enquiry, 'local community engagement' costs)*	[£]		
	Timescale for pre-development *(total pre-development period including pre-licensing, licensing, public enquiry)*	[Yrs]		
	Is a contingency included within the above pre-development costs? If so what % of the above cost is contingency? E.g., 10% of £1m (£100k contingency, £900k pre-development cost) / If no contingency is included what would the typical % included on top of pre-development cost be. *(E.g., for potential cost overrun and development uncertainty)*	[%]		
	Please provide the percentage distribution of costs over the pre-development period by year *(E.g., 50% of the cost upfront and the rest straight line, straight line for the full pre-development period or straight line with 50% of the cost back-ended)*	[%]		
	CONSTRUCTION COST *(Please note: this should exclude land costs, property and business rates, tax costs, rental and community benefit payments. These are requested separately in Additional Data section below.)*	**Unit**	**Response**	**Comment**
	For each cost entry, could you please specify the year to which the costs relate? Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.	[Yr]		

	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**Total capital (overnight) cost** *The cost item covers the projected design, procurement and construction costs, such as EPC costs if applicable. It should include the full capital cost EXCLUDING interest costs, land costs, property and business rates, tax costs, rental and community benefit payments.* *Please include the below costs in this total and list them separately where available. If not available separately, please state if included as part of the total.*	[£]		
	Please indicate whether the capital cost above includes offshore transmission costs.	[Text]		
	Owner's costs *[please provide total cost]* *(These include procurement cost, project management - owner's engineer, etc.)*	[£]		
	Grid connection costs *(E.g., exclude pre-connection securities, but include any upfront connection payments required)*	[£]		
	Substation and transformer costs (for offshore wind projects, this should be offshore transmission costs, i.e., OFTO) *Please separate from EPC, if data is available.*	[£]		
	Other infrastructure costs *[please provide total cost if applicable to the project]* *(If applicable, e.g., water, roads, sites works etc.)*	[£]		
	Is a contingency included within the above construction costs? If so, what percentage of the above cost is contingency? E.g. 10% of £10m (£1m contingency, £9m capex). If no contingency is included, what would be the typical percentage included on top of capex cost? *(E.g., for potential cost overrun and development uncertainty)*	[%]		
	Construction time period	[Yrs]		
	Distribution of costs over the construction period *(E.g., 50% of the costs upfront and rest straight line, straight line for full construction period or straight line with 50% of the costs back-ended)*	[%]		
	OPERATIONAL COST *(Please provide the following operating cost data on a unit cost basis – i.e., per MW or MWh as appropriate. If different from the unit in 'column C', please indicate the unit your cost figures are reported in.*	**Unit**	**Response**	**Comment**
	For each cost entry, could you please specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What is the total operating expenditure?** *(Includes all operations and maintenance costs, as well as all commercial costs such as asset management, insurance,*	[£/MW/a]		

	etc., and excludes connection and UoS charges as these will be requested later on.)			
	Fixed O&M cost *(Includes operating labour costs, planned and unplanned maintenance, lifecycle capital renewable cost.)*	[£/MW/a]		
	Variable O&M cost (please specify the components being considered)	[£/MWh]		
	Insurance cost	[£/MW/a]		
	Do you pay a community benefit package and if so how much?	[£/MW/a]		
	How does short-run marginal costs (SRMC) influence your dispatch behaviour? Please quantify total SRMC and individual components.	[Text]		
	What costs are associated with turning down / self curtailing when the asset could otherwise be generating?	[Text, £/MW]		
	Connection and UoS charge costs *(E.g., TNUoS, DUoS and OFTO)*	**Unit**	**Response**	**Comment**
	TNUoS (local) cost *(e.g. payment for utilising the local Transmission Network, including local substation charges and local circuit charges.)*	[£/MW/a]		
	TNUoS (wider) cost *(e.g. payment for utilising the wider Transmission Network, including locational and residual charges.)*	[£/MW/a]		
	DUoS cost *(e.g. charge for operating and maintaining local distribution network)*	[£/MW/a]		
	DECOMMISSIONING COST *(Please provide the following decommissioning cost data on a unit cost basis – i.e., per MW or MWh as appropriate. If different from unit in 'column C', please indicate the unit your cost figures are reported in.)*	**Unit**	**Response**	**Comment**
	For each cost entry, could you specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What are the total assumed decommissioning costs?**	[£]		
	What are the disposal and recyling costs net of any valuable scrap earnings?	[£]		
	TECHNICAL ASSUMPTIONS	**Unit**	**Response**	**Comment**
	Gross annual expected load factor *(Defined as average operating hours at full load equivalent divided by hours per year.)*	[%]		
Priority	**Average annual expected net load factor** *(Defined as average operating hours at full load equivalent divided by hours per year, net of all losses, e.g., wake losses, availability, electrical system losses, performance, environmental)*	[%]		

Plant availability during full annual operation % *(Availability is defined as the total proportion of time that a plant is able to produce electricity over a full year.)*	[%]		
Please describe how you expect plant availability to change over the plants lifetime.	[Text]		
Average annual degradation in plant performance (if applicable) %	[%]		
Plant operational life (technical life) i.e. expected maximum operational life	[Yrs]		
What is the wake loss as a percentage of annual production (applicable to onshore wind / offshore wind only)?	[%]		
To what extent have you been able to reduce wake loss? And are there any planned technological upgrades or operational strategy adjustments to further reduce wake effects in the future?	[Text]		
What turbine model are you using?	[Text]		
What turbine hub height are you planning to use?	[M]		
ADDITIONAL DATA	**Unit**	**Response**	**Comment**
Please provide the following costs, if available.			
Land / rental	[£]		
Property and business rates	[£]		
Tax	[£]		

Section A - Technology Specific Information

OFFSHORE WIND	Units	Response	Comment
What is the approximate distance from shore to your project?	[Km]		
What is the approximate average sea depth at the location of your project?	[M]		
What is the approximate distance from your project to the supply port?	[Km]		
What type of foundation is deployed and will it require replacement? *(e.g., jacket, monopole?)*	[Text]		
Is the project's export system HVAC or HVDC?	[Text]		
What is the average turbine size?	[MW]		
Do you think turbine size in terms of MW rating and physical scale will continue to increase or level off? If level off, what do you consider to be the maximum turbine scale to be reached and by when? *(MW, rotor diameter)*	[MW]		
Are there any current or near term constraints in the supply chain? *(e.g., supply of turbines, availability of ships?)*	[Text]		
What proportion of Total Capital Expenditure, as presented in cell B38 on the Section A tab, is related to the following:	[%]		
Turbine supply			
Turbine transportation & installation			
Foundation supply			
Foundation transportation & installation			
Cables (Inter-array) supply			
Cables (Inter-array) transportation & installation			
Cables (Export system / grid connections) supply			
Cables (Export system / grid connections) transportation & installation			
Offshore substation EPC			

What, if any, differences in costs would there be between an offshore wind project connecting to a bootstrap, compared to connecting to the onshore network via a radial connection? What elements of project costs might differ, and what would be the scale of these costs? *(Impact on construction and operational costs related to the generation asset and balance of plant - include export system.)*	[Text]		
What, if any, differences in costs would there be between an offshore wind project connecting to a multi-purpose interconnector, compared to connecting to the onshore network via a radial connection? What elements of project costs might differ and what would be the scale of these costs? *(Impact on construction and operational costs related to the generation asset and balance of plant - include export system.)*	[Text]		
ONSHORE WIND	**Units**	**Response**	**Comment**
What is the average turbine size?	[MW]		
Do you think turbine size in terms of MW rating and physical scale will continue to increase or level off? If level off, what do you consider to be the maximum turbine scale to be reached and by when? *(MW, rotor diameter)*	[MW]		
Are there any current or near term constraints in the supply chain? *(E.g., supply of turbines, transformers, availability of trucks, etc)*	[Text]		
What proportion of Total Capital Expenditure, as presented in cell B38 on the Section A tab, is related to the following:	[%]		
Turbine supply			
Turbine transportation & installation			
Foundation construction			
Electrical BoP (inter-turbine cables, switch gear, protection equipment, transformers, auxiliary systems)			
Civil works (ground works, hardstanding areas, drainage, access roads, substation building, compound areas)			
What, if any, differences in costs would there be between developing a full repowered onshore wind farm compared to a new build onshore wind farm? What elements of project costs might differ and what would be the scale of these costs?* *(E.g., what proportion of the total cost per MW does it cost to repower onshore wind project compared to a new project?)*	[Text]		
SOLAR PV	Units	Response	Comment
What technology is being used in the project? (E.g., panel manufacturer, cell material (Mono/Poly-crystalline, Thin-film, etc.), bifacial)	[Text]		
Is the solar installation using either a tracker or fixed structure?	[Text]		
How do costs vary with advances such as optimised site layouts, improvements in panel efficiency and active output controls?	[Text]		
What country is the solar technology from? (E.g., China, Germany)	[Text]		
Are there any current or near term constraints in the supply chain? (E.g., supply of panels, invertors , transformers, etc.)	[Text]		
What is the average annual expected level of degradation?	[%]		
What proportion of Total Capital Expenditure, as presented in cell B38 on the Section A tab, is related to the following:	[%]		
PV module			
Inverter			
Electrical balance of plant (cables, switch gear, protection equipment, transformers, auxiliary systems)			
Steel Mounting / racking systems			
Civil works (ground works, drainage, access roads and public rights of way, screening, substation building, compound areas)			

How do costs vary with co-located storage? ***(E.g., generation assets only, including cost synergies with associated infrastructure)***	[Text]		

Section B – Future Outlook

Information about your company	Units	Response
Are you a developer, investor or operator?	[Text]	
What is the technology type?	[Text]	*Please select*
Amount of technology/installed capacity deployed by you globally to date:	[MW]	
Amount of technology/installed capacity deployed by you in Great Britain to date:	[MW]	
Amount of technology/installed capacity currently in development by you in GB. What is in your immediate pipeline?	[MW]	
Amount of technology/installed capacity expected to be developed by you in GB. How much new installed capacity do you expect to deploy between now and 2030, and from 2030 onwards?	[MW]	

General questions on your portfolio of renewable generation projects	Units	Response
What do you consider the key drivers to be behind:		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[Text]	
Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[Text]	
Operational costs *(e.g., exchange rates, fuel costs, labour costs, others)*	[Text]	
What percentage change in real terms have you experienced between 2021 to date? How has each category been affected by recent macro-economic factors such as the COVID pandemic, war, energy prices, inflation etc.? (E.g., please provide an overall % estimate for each category and your assumptions behind this. For instance, 'In our project cost modelling, we have seen construction costs increase by 5%'.)		
Pre-development costs	[%, text]	
Construction costs	[%, text]	
Operational costs	[%, text]	
How long do you expect it to take for changes (increases and decreases) in commodity prices to feed through to costs faced by developers?	[Text]	
What are your expectations for the likely percentage change in cost <u>in real terms</u> between 2025 and 2035? *(E.g., please provide an overall % estimate for each category and your assumptions behind this. For instance, 'In our discounted cashflow modelling, we assume fuel costs will increase by 5%' .)*		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[%, text]	
Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[%, text]	
Operational costs *(e.g. exchange rates, fuel costs, labour costs, others)*	[%, text]	
What are your qualitative views on how costs will change between 2035 and 2050? *(E.g., please provide us with your views on what factors will influence longterm costs.)*		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[Text]	

Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[Text]	
Operational costs *(e.g., exchange rates, fuel costs, labour costs, others)*	[Text]	

A.2 Questionnaire for suppliers

<table>
<tr><th>#</th><th>Questions</th><th>Your response</th></tr>
<tr><td>1</td><td>Please describe the technical specification of the [component(s)] that you supply.

Please provide units where appropriate, e.g., MWe, rotor diameter, etc</td><td><table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
<tr><td>2</td><td>Please provide us with any up-to-date costs based on firm project information. Please specify the currency and units,

e.g., £/MW, etc.</td><td><table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
<tr><td>3</td><td>What is the % breakdown of the main materials?</td><td><table><tr><th>Component Name</th><th>% breakdown</th></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr></table></td></tr>
<tr><td>3</td><td>What costs can you provide for the materials or sub-components, prioritising the most costly?</td><td><table><tr><th>Component Name</th><th>Cost % breakdown</th></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr></table></td></tr>
<tr><td>4</td><td>What can you tell us about recent changes to costs in the past 3 years? Please consider the prompts below before answering;
What change have you experienced (in percentage terms)?
What do you believe are the drivers for this change? (examples COVID pandemic, war, energy prices, inflation….)
How have you managed these changes? e.g. cost increases, absorption, combination, etc.
e.g., steel costs, exchange rates, energy costs, labour costs, transportation costs, other…</td><td>Response:
<table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
</table>

5	What factors do you anticipate will impact future costs? Please specific the timeframe your answers refer to (e.g., 2024 – 2025, 2024 – 2030, 2030 – 2035, 2035 – 2050) *e.g., steel costs, exchange rates, energy costs, labour costs, transportation costs, others*	Response: Timeframe: | Unit:
6	What do you believe are the cause(s) or driving forces behind these factors affecting future costs?	Year: | Unit:
7	Is there anything else you would like to share with Arup and DESNZ concerning costs?	Year: | Unit: