IEA Wind Task 26

Offshore Wind Farm
Baseline Documentation

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List of Abbreviations

BoS	balance of system
CapEx	capital expenditure
CLV	cable laying vessel
CRMF	Cost Monitoring Framework
CTV	crew transfer vessel
DSV	diving support vessel
ECN	Energy Research Centre of the Netherlands
FID	Final Investment Decision
HLV	heavy lift vessel
km	kilometre
kV	kilovolt
LCOE	levelised cost of energy
m	metre
m/s	metres per second
MW	megawatt
MWh	megawatt-hours
NREL	National Renewable Energy Laboratory
O&M	operations & maintenance
OpEx	operating expenditure
ORE Catapult	Offshore Renewable Energy Catapult
SINTEF	SINTEF Energy Research
t	metric tonne
TKI	TKI Wind Op Zee
WACC	weighted average cost of capital
yr	year

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1 Executive Summary

This document has been produced to provide the definition and rationale for the Baseline Offshore Wind Farm established within IEA Wind Task 26 – Cost of Wind Energy. The Baseline has been developed to provide a common starting point for country comparisons and sensitivity analysis on key offshore wind cost and value drivers. The baseline project reflects an approximate average of the characteristics of projects installed between 2012 and 2014, with the project life assumed to be 20 years. The baseline wind farm is located 40 kilometres (km) from construction and operations and maintenance (O&M) ports and from export cable landfall. The wind farm consists of 100 4-megawatt (MW) wind turbines mounted on monopile foundations in an average water depth of 25 metres (m), connected by 33-kilovolt (kV) inter-array cables. The arrays are connected to a single offshore substation (33kV/220kV) mounted on a jacket foundation, with the substation connected via a single 220kV export cable to an onshore substation, 10km from landfall. The wind farm employs a port-based O&M strategy using crew-transfer vessels.

Wind and wave regime data has been sourced from the Horns Rev 3 site in Denmark (Energinet.dk 2015). This site has a wind speed of 9.9 metres per second (m/s) at 100m above sea level, which is generally higher than average for installed offshore wind projects. Although this site may have a somewhat higher than average wind speed, it provides the necessary, publicly available resource data required to develop the baseline model parameters.

The baseline wind farm applies a 70/30 debt/equity ratio with resulting pre-tax weighted average cost of capital (WACC) of 8.00% (7.10% post-tax). A generic tax rate of 25% has been applied, intended to be representative of the range of tax rates in Task 26 member countries.

The site properties and technology choices have been used to estimate capital expenditures (CapEx), operating expenditures (OpEx), and net energy production. These assumptions, together with the project life and financing inputs, have been used to generate a baseline levelised cost of energy (LCOE).

The inputs and estimates are detailed throughout this document. Tables 1, 2, and 3 summarise the baseline CapEx, OpEx, and energy output, respectively.

Table 1: Task 26 Baseline CapEx Summary

Description	€m	€/kW
Turbines Subtotal	661	1,653
Foundations Subtotal	343	856
Electrical Infrastructure Subtotal	267	668
Other Capex Subtotal	197	493
Total Construction CapEx	**1,468**	**3,670**
Development	48	119
Grand Total	**1,516**	**3,789**

Table 2: Task 26 Baseline OpEx Summary

Description	€m/year	€/kW
Fixed operating costs	12.2	30.4
Variable costs	27.1	67.5
Total O&M (Preventive & Corrective)	**39.3**	**97.9**

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Table 3: Task 26 Baseline Energy Output

Description	Units	Reference Values
Gross Annual Energy Production	gigawatt hours (GWh) / year	2,065,077
Total Losses	%	17.8%
Net Annual Energy Production	GWh / year	1,696,732
Net Capacity Factor	%	48.4%
Full Load Hours	hours / year	4,242

2 Background

The objective of IEA Wind Task 26 is to provide information on cost of wind energy to understand past, present, and anticipated future trends using consistent, transparent methodologies as well as how wind technology compares to other generation options within the broader electricity generation sector. Task 26 will continue to add data and analysis, develop methodologies, and enhance collaboration between member countries to improve the international knowledge base.

One activity within Task 26 aims to estimate the current cost of offshore wind energy and identify major cost drivers in each participating country to provide insight into differences among countries. To fulfil this part of the task, a representative baseline offshore wind farm description was developed. This baseline provides an opportunity for two types of analysis to better understand and define cost drivers for offshore wind energy:

1. A common cash flow model[1] can be used to explore the impact of market and policy factors on the delivered cost of offshore wind in each country under constant assumptions about baseline technology and site characteristics.
2. Bottom-up, engineering-based models (e.g., electrical infrastructure, O&M) under development by various countries can be verified, first by exercising the models to define baseline costs, and second, by conducting sensitivity analysis around the baseline project description by varying technology assumptions and site characteristics relative to the baseline technology description.

IEA Wind Task 26 participants expect that the insights gained through sensitivity analysis and model comparisons, will lead to improved understanding of cost drivers spanning policy, regulatory structure, technology, and site characteristics. This information is expected to be valuable to decision makers, including policymakers and research management organisations, who are aiming to reduce the cost of offshore wind energy. The task is also expected to result in improved cost and performance models. By making detailed modelling assumptions available to the research community, it is hoped that the baseline definition will serve as a starting point for reasonable and representative assumptions for future cost and performance modelling efforts within the broader community.

3 Baseline Definition Process

The baseline site is intended to include environmental characteristics and technology assumptions which are reasonably representative of offshore wind farms installed in Northern Europe between 2012 and 2014, as detailed in Appendix A. The decision to focus the baseline on projects that have been recently installed was driven by a desire to be able to validate the baseline cost and performance estimates against empirical data from realised projects.

The Task members recognise that many of the projects that are under development are increasingly located in deeper water and further from shore, which will likely have implications for the technology

[1] Task 26 participants are using a common cash flow model developed by TKI.

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and logistical philosophies that will be employed. Further, there has been significant innovation relative to the technology that was available to projects installed between 2012 and 2014. For example, many projects that closed financing in 2015 have opted for turbines with nameplate capacities ranging between 6MW and 8MW, a 50% to 100% increase relative to the average turbine installed between 2012 and 2014. The Task participants aim to explore the implications of these changing site conditions and new technologies on the cost structure through sensitivity studies that will be conducted over the next period of Task 26 activity, which extends from October 2015 to October 2018.

The Capex, OpEx, performance, and financing assumptions have been derived from a combination of bottom-up component modelling and higher-level industry data. CapEx assumptions have been formulated by model comparison between the National Renewable Energy Laboratory (NREL), TKI Wind Op Zee (TKI), and Offshore Renewable Energy (ORE) Catapult. OpEx assumptions have been formulated by model comparison between NREL and SINTEF Energy Research (SINTEF). Performance assumptions have been formulated by TKI. Financing assumptions are based on trends observed in the participant countries. The detailed approach for estimating cost and performance is described in Section 4.

4 Baseline Project Definition

The baseline project reflects an approximate average of the characteristics of projects installed between 2012 and 2014. The project is defined to a level of detail that is sufficient for cost and performance modelling purposes, including hourly wind speed and significant wave height data sourced from the Horns Rev 3 site in Denmark (Energinet.dk 2015). The following subsections describe the assumptions covering the general project, turbines, balance of system (BoS), O&M, finance, and performance.

4.1 Wind Farm Assumptions

The baseline offshore wind farm is defined to be broadly representative of commercial-scale wind farms installed between 2012 and 2014 in Europe. Table 4 summarises the Task 26 baseline project parameters.

Table 4: Task 26 Generic Baseline Project Description

Description	Unit	Reference Value
Wind farm rating	MW	400
Number of Turbines	#	100
System design life	yrs	20
Average Wind speed @ 100m mean sea level	m/s	9.90
Water depth	m	25
Distance to construction port	km	40
Distance to O&M port	km	40
Distance to cable landfall	km	40
Turbine spacing	Rotor diameters	5 X 9
Wind & wave data	Source	Horns Rev 3

The Task 26 Baseline consists of 100 four-MW wind turbines arranged in a grid that is spaced at five rotor diameters perpendicular to the prevailing wind direction by nine rotor diameters parallel to the

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prevailing wind direction. The water depth at this baseline site is 25m, and it is located 40km from both the point of cable landfall and the port used to stage construction and maintenance activities.

As mentioned above, the metocean data were sourced from the Horns Rev 3 site in Denmark, one of the few sites where a full metocean dataset has been made publicly available.[2] This site has a wind speed of 9.9 metres per second (m/s) at 100m above sea level, which is generally higher than average for installed offshore wind projects. Although this site may have a somewhat higher than average wind speed, it provides the necessary, publicly available resource data required to develop the baseline model parameters. This is important because detailed, correlated wind and wave conditions are needed to effectively model installation and operation activities to estimate the associated cost and performance.

4.2 Turbine Assumptions

The turbine rating of projects installed in Europe between 2012 and 2014 ranged between 2.3MW and 6.15MW, with an average of approximately 4MW (see Appendix A for further details). The Task 26 baseline turbine is a generic 4MW horizontal axis machine with a high-speed gearbox and doubly fed induction generator. The turbine has a 125m rotor diameter and a hub height of 90m. The parameters are described in Table 5.

Table 5: Task 26 Generic Baseline Turbine Description

Description	Units	Reference Values
Rating	MW	4.00
Rotor diameter	m	125
Hub height	m	90
Gearbox type	Type	3-stage
Generator	Type	Asynchronous
Max rotor coefficient of power (C_p)		0.45
Tip speed ratio at max C_p	m/s	7.25
Cut-in wind speed ($V_{cut\text{-}in}$)	m/s	3
Rated power wind speed (V_{rated})	m/s	12
Cut-out wind speed ($V_{cut\text{-}out}$)	m/s	25

The power curve for this generic IEA Wind Task 26 baseline was defined using NREL's Wind Turbine Cost and Scaling model for a 4MW turbine; a 125m rotor diameter; and a three-stage, asynchronous drivetrain as a starting point (Fingersh et al. 2006). To ensure that this power curve was representative, it was compared against eight real offshore wind turbine power curves with capacity normalised to 4MW. The comparative analysis revealed that the power curve was overly aggressive at the upper end of Region 2 (as the turbine approaches the rated power). To correct for this problem, the power curve was tuned to match the general profile of the real power curves in Region 2. Figure 1 shows the power curve estimated by the Cost and Scaling model (Rev. 1), the normalised real turbine power curves (dotted lines), and the tuned power curve (Rev. 2) that is used as the baseline turbine in this document. Note that the power curve for the baseline shows the baseline turbine capturing more energy because

[2] Energinet.dk, the Danish transmission system operator that will have responsibility for connecting Horns Rev 3 to the grid, published the metocean dataset, which is available upon request. The metocean data are described in the *Horns Rev 3 Offshore Wind Farm – Met-Ocean Report on Wind and Waves* (Energinet.dk 2015). Data for extraction point 7 on the Horns Rev 3 site were used for the baseline. Wind data were extrapolated to a hub height of 90m using a power law and the wind shear exponent of 0.076 stated in this report. Additional details on the treatment of the metocean data for O&M modelling are described in Appendix C.2.6.

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of the larger rotor-to-generator ratio relative to the majority of real machines (lower specific power). The Rev. 2 power curve data are shown in Table B-1 in Appendix B.

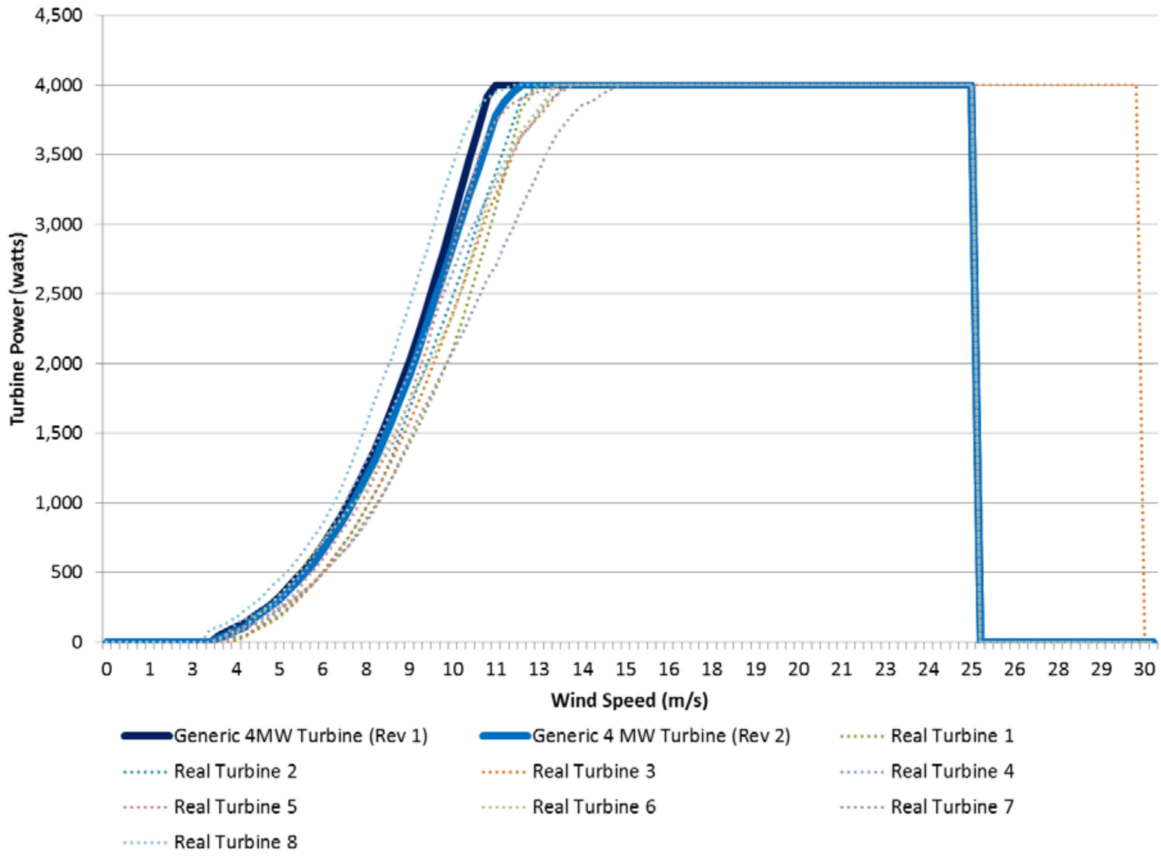

Figure 1 Power curve for 4MW generic baseline turbine

4.3 Balance of System Assumptions

Table 6 describes the BoS, or non-turbine, aspects of the Task 26 baseline project. While offshore wind projects have adopted a wide variety of designs and logistical strategies for BoS elements, the governing philosophy for defining the baseline parameters were to select technologies that are most appropriate for the combination of site conditions (Table 4) and turbine assumptions in Table 5.

Table 6: Task 26 Generic Baseline BoS Description

Description	Units	Reference Values
Substructure & foundation	Type	Monopile
Array cable configuration	Type	Radial
Array cables voltage	kV	33
Array cable size	mm^2	3x240, 3x630
Substation	kV	33kV/220kV
Substation substructure	Type	Jacket
Export cable number	#	1
Export cable voltage	kV	220
Export cable size	mm^2	3x1,600
Offshore export cable length	km	40
Onshore cable length	km	10
Foundation installation	Vessel	Jack-up vessel

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Description	Units	Reference Values
Array cable installation	Vessel	Cable vessel
Turbine installation	Vessel	Turbine installation vessel
Export cable installation	Vessel	Cable vessel
Substation installation	Vessel	Shear-leg Vessel

Monopiles were the substructure of choice for turbines installed between 2012 and 2014 in commercial-scale wind farms, with a 79% market share (see Appendix A). Multi-pile foundations, including four-leg jackets, tri-piles, and tri-pods, had an approximate 19% market share; however, multi-piles were only used in projects with turbines rated at 5MW or more. Gravity-based foundations accounted for the remainder. The Task 26 baseline uses a monopile foundation type because of the water depth at the project site (25m) and turbine size (4MW). Task 26 plans to explore the sensitivity of costs to other substructure types in future work.

The electrical system consists of medium-voltage array cables that are laid in a radial configuration to collect power from the turbines and deliver it to the offshore substation where power is transformed to 220kV and exported via a single cable to shore. The array cables are rated at 33kV and use two diameters to minimise cost while ensuring that each string of cables can accommodate the full power output of the turbines. Array cable with a cross-section of 240mm^2 is used to connect the first six turbines, which total 24MW of capacity, which approaches the maximum power transfer of 26MW. The cable switches to 630mm^2 for the last three turbines to connect each individual string to the offshore substation. The 33kV/220kV offshore substation consists of a topside, which weighs approximately 2,900 metric tonnes (t) and contains, among other items, electrical conversion equipment, emergency accommodations, fire protection system, emergency generator, fuel and water storage, and a 6t crane to lift supplies from vessels. Because of the weight and water depth, it is assumed that this topside is mounted on a jacket foundation.

The installation of components is assumed to be performed using a simple approach that is able to be broadly generalised. A jack-up vessel installs the monopile and transition piece and then grouts them together. A cable installation vessel lays and buries cable to a depth of 1m between turbines. A purpose-built turbine installation vessel later installs the tower, nacelle, and rotor, lifting each component separately. The substation is installed by a shear-leg crane vessel, and an export cable is laid from point of cable landfall to the substation.

4.4 O&M Assumptions

The site is close enough to shore that it is reasonable for the project to use a standard O&M philosophy where maintenance activities are staged out of the O&M port. The main baseline assumptions of the O&M of the Task 26 offshore baseline project are given in Table 7. Additional details are provided in Appendix C.

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Table 7: Task 26 Generic Baseline Operations and Maintenance Description

Description	Units	Reference Values
Fixed costs		See Table C-9 for details
Maintenance/access strategy	Type	Port-based, using crew transfer vessels for access
Number of crew transfer vessels	#	~ 3
Crew transfer vessel, limited by significant wave height for access	m	1.8
Jack-up vessel charter – practice and strategy	Type	Basic jack-up charter strategy, chartered when needed for corrective maintenance (major replacements)
Jack-up vessel day rate	k€/day	140
Vessel data		See Table C-2 for other vessel details
Preventive maintenance	Maintenance type – hours/yr/turbine	Annual service – 50 See Table C-5 for details and other preventive maintenance tasks
Failure rates for corrective turbine maintenance	Maintenance type – failures/yr/turbine	Manual resets – 5 Minor repair – 3 Major repair – 0.3 Major replacement – 0.11 Remote reset – 7 See Table C- 3 for other maintenance details
Failure rates for corrective balance of system maintenance	Maintenance type – failures/yr/component	Small transformer repair – 0.45 Large transformer repair – 0.05 Cable replacement – 0.0004 See Table C-6 for other maintenance details
Number of technicians	#	~ 30
Technician salary	k€/yr	100

For the base case, conventional (standard), but fairly robust crew transfer vessels (CTVs), chartered by the project under long-term agreements, are based at the O&M port, and are available for maintenance activities at all time. Other vessels, including supply vessels, jack-up vessels, and cable repair vessels, are chartered when needed, typically in response to a failure event. The charter strategy for these vessels is assumed to be relatively basic: all supplemental vessels are chartered on the spot market when corrective maintenance is required, which means that there is some time required to secure and mobilise the vessel to the project site before the repair can take place. A single working shift for technicians is assumed for regular maintenance and smaller repairs; for maintenance requiring chartered jack-up vessels, it is assumed that work is carried out 24 hours a day.

The O&M strategy assumes that the project owner will choose to conduct a repair after a failure occurs to minimise downtime. The owner in this strategy does not actively seek to optimize repairs by choosing to postpone major repairs so that they can be performed by the vessel in batches or during a season when weather conditions are likely to be more favourable. Note, however, that the models are set up such that the same jack-up vessel can be used for multiple repairs when already in the wind

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farm. No advanced strategy for utilising condition monitoring system data and remaining life-time prediction is assumed, and preventive replacement of large components is not considered explicitly.

4.5 Financing Assumptions

Offshore wind projects have been developed under a number of different financial structures, which are driven by a number of factors, including market structure, incentive design, and, most importantly, the characteristics and preference of the project sponsor. The majority of projects installed to date have been financed on utility balance-sheets, with ownership stakes often sold or re-financed after start of commercial operation to free up capital. There is, however, an accelerating trend toward project financing (also referred to as non-recourse financing)[3] as both utilities and independent power producers seek to secure large amounts of capital at low rates, thereby reducing the cost of generation (Freshfields Bruckhaus Deringer 2014).

The Task 26 baseline project is assumed to be financed with a non-recourse structure. Table 8 summarises these parameters, which are based on averages from publically available data. Note that many of the parameters involved in determining the financial structure, such as debt rate, debt to equity ratio, debt term, tax rate, depreciation schedule, and decommissioning bond, are largely driven by country-specific factors. Generic values are assumed for the baseline (shown in Table 8); the impact of country-specific factors will be considered in future sensitivity studies.

Table 8: Task 26 Generic Baseline Financial Structure Description

Description	Units	Reference Values
Debt-to-equity ratio	Ratio	70:30
Equity rate	%	15.00
Debt rate	%	5.00
WACC (pre-tax)	%	8.00
WACC (post-tax)	%	7.10
Debt term	yrs.	15
Project life	yrs.	20
Contract structure	Type	Multi-contract
Debt service reserve account	Type	6 months
Contingency reserve	Type / Rate	Model
Bank fees	%	3.00
Tax rate	%	25
Depreciation	Type / Rate	15-year flat rate
Decommissioning bond	Type / Rate	Not included

The financing structure assumes that 70% of the upfront CapEx is sourced from debt, with the remainder sourced from equity. The cost of equity is assumed to be 15%, which is reasonable given that the equity investor takes the majority of the risk associated with the project.[4] The all-in cost of debt, after accounting for the cost of interest rate hedges and over the full loan amortisation period, ranges between 4.5% and 5.5%; the average is used for the Task 26 baseline project. The loan tenor

[3] Nonrecourse debt is an investment in which the providers (typically commercial banks) supply capital that only has claims on the future cash flows of the project and does not include claims on equity investor assets beyond the boundary of the project. These investors are conservative and conduct considerable due diligence to ensure that their downside risk exposure (in which returns are lower than expected) is limited.

[4] Debt is structured such that the debt investor has first claim on project assets in the event that the project becomes financially distressed.

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typically varies between 10 and 15 years, depending on the country; the tenor is limited by the term of the subsidy available to the project to include a 2- to 5-year buffer between the loan repayment date and end of the power offtake agreement. A tenor of 15 years is assumed for the baseline project.

It is assumed that the project is contracted using a multi-primes structure, where the project is divided into three to five specific work packages. For example, the project might be split such that one contractor delivers the turbines, a second delivers the foundation, a third installs foundations and turbines, and a fourth supplies and installs the electric system. While many permutations are possible, individual contractors in these take responsibility for the turnkey delivery of their specific work packages, with interfaces typically defined by contractual agreements. It is assumed that debt investors will require the project to set up a contingency reserve at the project level to cover any issues that may arise during procurement and construction. It is also assumed that the project will set up a debt service reserve account that is sized to cover six months of debt payments to protect the solvency of the project in the event that its ability to generate revenue is delayed or interrupted.

Tax rates and depreciation schedules are highly market specific.[5] Corporate income taxes in Task 26 member countries with installed commercial-scale offshore wind farms range from 20% in the United Kingdom to 35% in the United States; 25% is used for the baseline as being representative of the range. Depreciation schedules vary from the five-year Modified Accelerated Depreciation Schedule in the United States to the 16-year linear depreciation schedule in Germany; a 15-year flat rate depreciation schedule is used for the baseline analysis. Sensitivities to both country-specific tax rates and depreciation will be explored in future work.

4.6 Performance Assumptions

Performance assumptions for the Task 26 baseline project use the turbine power curve shown in Figure 1; the metocean dataset from the Horns Rev 3 site; and standard assumptions about environmental, technical (wake, turbine operating parameters), and electrical losses. Availability results from the O&M modelling exercise (presented in Appendix C.5.1) feed into performance calculations. Table 9 summarises the assumptions that are used to calculate gross and net energy production from the Task 26 baseline project.

Table 9: Task 26 Baseline Project Performance Assumptions

Description	Units	Reference Values
Turbine power curve	Type	Generic 4MW
Availability (time-based)	%	94.1
Availability (energy-based)	%	93.7

At the time of writing, several of the site-specific loss categories, such as wake losses and electrical losses, are based upon the experience of task participants. Site-specific analysis to quantify wind farm performance is an active area of research being conducted by Task 26 participants and others that will be used to substantiate these assumptions in the future as results become available.

[5] An overview of tax and subsidy regimes in key European markets can be found in TKI Wind op Zee (2015), *Subsidy schemes and Tax Regimes* http://www.tki-windopzee.nl/files/2015-09/1442828347_20150401-rap-subsidy.and.tax.policies-pwc-f.pdf

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5 Resulting Baseline Financial Model Inputs

5.1 Annual Energy Production

The gross annual energy production was derived using a generic 4MW power curve (see Table 5 for cut-in, rated, and cut-out wind speeds), mean wind speed at 100m of 9.9m/s (9.8m/s at 90m hub height) and assumed Weibull shape and scale parameters for the distribution of wind speeds. Wind farm availability losses are given by the estimates of the wind farm availability produced by O&M models, as described in detail in Appendix C. We have used the average of the estimates for time-based availability from two models: the NOWIcob model and the ECN O&M Tool. Table 10 describes the baseline performance model results.

Table 10: Task 26 Baseline Performance Model Results

Description	Units	Reference Values
Gross annual energy production	MWh / year	2,065,077
Wind farm availability losses	%	5.9
Wake losses	%	9.0
In-field cable losses	%	1.5
Export cable losses	%	1.3
Turbine transformer losses	%	1.0
Offshore high voltage substation transformer losses	%	0.3
Total losses	%	17.8
Net annual energy production	MWh / yr	1,696,732
Net capacity factor	%	48.4
Full load hours	Hours / MW/ yr	4,242

5.2 CapEx

CapEx for the Task 26 baseline project were estimated using turbine costs based on market data and BoS models from TKI (Prinsen et al. 2015, unpublished), NREL (Maples et al. 2013), and ORE Catapult (Smart et al. 2015, unpublished). The BoS models were run with the design and strategy assumptions outlined in Section 4.3. Results from the three models were averaged in each major cost category to develop the baseline CapEx estimates, except where information did not exist or was determined to be of limited confidence. For example, NREL's BoS model does not account for onshore electrical infrastructure costs. The CapEx summary is shown in Table 11.

Table 11: Task 26 Baseline CapEx Model Results

Description	€m	€/kW
Turbine supply	598	1,496
Turbine installation & commissioning	63	157
Turbines Subtotal	**661**	**1,653**
Foundations supply	257	642
Foundations installation	86	215
Foundations Subtotal	**343**	**856**
Array cable supply	41	103
Array cable installation	46	115
Offshore substation	67	168
Offshore export cable supply & install	63	157
Onshore export cable supply & install	18	46

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Description	€m	€/kW
Onshore substation & grid connection	32	79
Electrical Infrastructure Subtotal	**267**	**668**
Construction insurance	19	48
Project management	50	126
Contingency	127	318
Other Capex Subtotal	**197**	**493**
Total Construction Capex	**1,468**	**3,670**
Development	48	119
Grand Total	**1,516**	**3,789**

5.3 OpEx

Fixed operations costs (i.e., those that are not tied to offshore logistics) have been estimated based on published literature and the experience of NREL and SINTEF. Maintenance costs that depend on metocean conditions, failure rates, and maintenance strategy were estimated using two O&M models: the NOWIcob model and the ECN O&M Tool. Brief descriptions of these models and the detailed assumptions made in the modelling are given in Appendix C. Where OpEx contributions are the result of this kind of bottom-up modelling, the values given below are the results of averaging results from the two models. Table 12 summarises the key OpEx results for the baseline project.

Table 12: Task 26 Baseline OpEx Model Results

Description	€m/year	€/kW	Notes
Total O&M (preventive & corrective)	39.4	97.9	O&M modelling based on site weather assumptions
- Fixed operating costs	12.2	30.4	Mid-point of range of observed costs for typical European project (assuming ownership of export system)
- Technicians	2.7	6.6	Average of the estimates from NOWIcob model and the ECN O&M tool
- Spare parts	7.9	19.6	Average of the estimates from NOWIcob model and the ECN O&M tool
- Vessels	16.4	40.8	Average of the estimates from NOWIcob model and the ECN O&M tool
- Onshore electrical maintenance	0.2	0.5	Mid-point of range of observed costs for typical European project

6 LCOE Results

The inputs documented above were run through the Cash Flow Model. The resulting post-tax equity LCOE was €146/MWh (2014 real), equivalent to US$190/MWh at an exchange rate of US$1.3/€1. The LCOE breaks down as shown in Figure 2. This LCOE value is at the low end of the range expected for a wind farm reaching completion in 2012–2014.[6] The LCOE is dependent on the Cash Flow Model inputs, and so changing any of the baseline assumptions would result in a change to the baseline LCOE.

[6] The Cost Monitoring Framework (CRMF) (ORE Catapult February 2015) documented UK aggregate LCOE for projects reaching work completion in 2012–2014 at £131/MWh (2011 real). Applying three years of inflation of approximately 8% gives a 2014 figure of £141/MWh. Assuming these projects would have been subject to British

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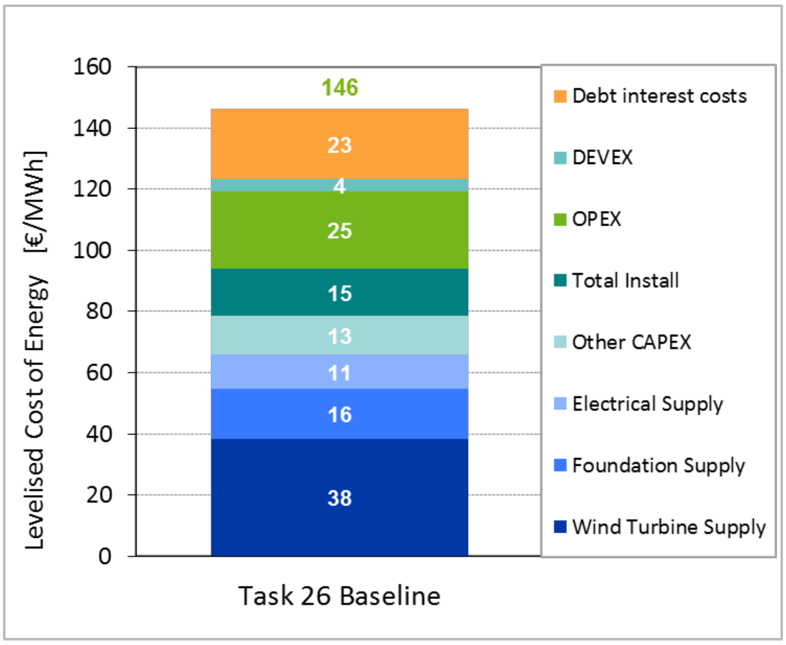

Figure 2: Task 26 baseline project LCOE results

7 Next Steps

Based on the baseline project definition and the TKI cash flow model developed in the prior phase, a sensitivity analysis will be conducted. Further definition of a common analysis framework will allow a systematic analysis of the impact on cost of energy based on changes to a range of parameters. Country-specific market and policy aspects of offshore wind farms will be explored. A technical report summarising the baseline project, sensitivity analysis to primary parameters, and country-specific market and policy aspects will be published.

A number of potential model comparison activities have been identified for collaboration among participants. These include impacts of turbine scaling on non-turbine capital investment costs (e.g., installation, electrical infrastructure); floating offshore wind technology; O&M cost estimates; and others. In each case, interested parties will develop an approach to test their respective models using the baseline technology description. By harmonising inputs to the respective models, the algorithms that compute cost outputs as well as the type of cost outputs can be compared, providing insight into the accuracy of component cost models. Collaborative papers or journal articles may result from this analysis.

Discussion around model characteristics and fidelity for different cost analysis purposes will provide insights into future model development work.

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pound/Euro exchange rates representative of ~2010–2012 Final Investment Decision (FID) years in the region of €1.18/£1, gives €167/MWh. Significant differences between "typical" UK inputs driving the CRMF figure and the inputs used in this baseline are the lower discount rate applied here (8% pre-tax vs ~9.24%) and the high capacity factor based on a site with a particularly good wind regime. While the CRMF results are expressed at pre-tax project level, the use of the appropriate discount rates (pre-tax project vs. post-tax equity) makes the results comparable.

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Appendix A. Wind Farms Installed in Northern Europe 2012–2014

The analysis of 19 utility-scale wind farms that were commissioned in total or in part during the 2012–2014 period in Belgium, Sweden, the United Kingdom, Denmark, and Germany include the following wind farms which were installed in 2014 but commissioned in 2015: Nordsee Ost, Dan Tysk, Global Tech I, and Trianel Windpark Borkum 1 (Germany), and Gwynt Y Mor (United Kingdom).

Table A-1 includes the weighted average parameters, based on 5,869MW installed, compared to the baseline reference values.

Table A-1: 2012–14 Project Sample vs. Baseline Reference Values

Description	Unit	2012–2014	Baseline Value
Wind plant rating	MW	309	400
Number of turbines	#	79	100
Turbine rating	MW	3.96	4.00
Rotor diameter	m	115.7	125
Hub height	m	85.9	90
Water depth	m	21.8	25
Distance to shore	km	35.9	40
Substructure & foundation	Type	79% monopile	Monopile

Figure A-1 shows the size of the wind farms and the year installation was finished. The average installed capacity of these offshore wind farms was 308.9MW. The variation is quite large between the 48MW of Kårehamn in Sweden and the 630MW of London Array in the United Kingdom.

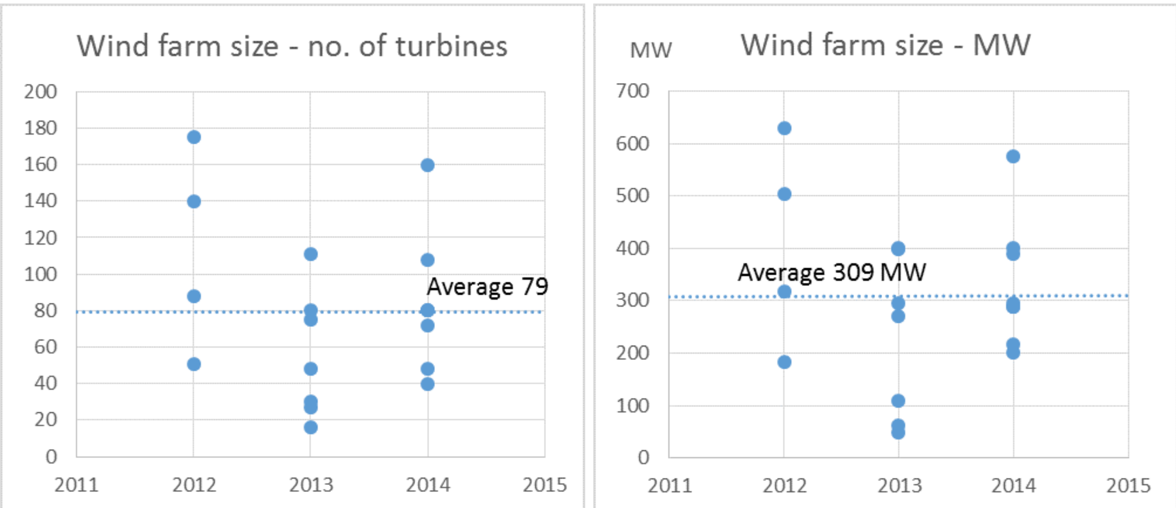

Figure A-1: Spread of wind farm sizes in megawatts and in number of turbines.
Source: JRC database of offshore wind farms

The average number of turbines was 79.4 turbines per wind farm—the two extremes are 16 (Kårehamn) and 175 (London Array) turbines.

The average turbine rating is 3.96MW, and the weighted average is 3.89MW. The smallest turbine installed was the SWT-2.3-101 at Teesside with 2.3MW, and the largest were the Senvion 6.2M126 with 6.15MW installed at Nordsee Ost (Germany) and Thornton Bank II & III (Belgium).

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The rotor diameter increases with time throughout the period and reaches an average 115.7m or a weighted average slightly smaller at 115.4m, as shown in Figure A-2. The Teesside wind farm (UK) has the lower figure (101m), and the maximum corresponds to the 6.2M126 turbines with 126 m.

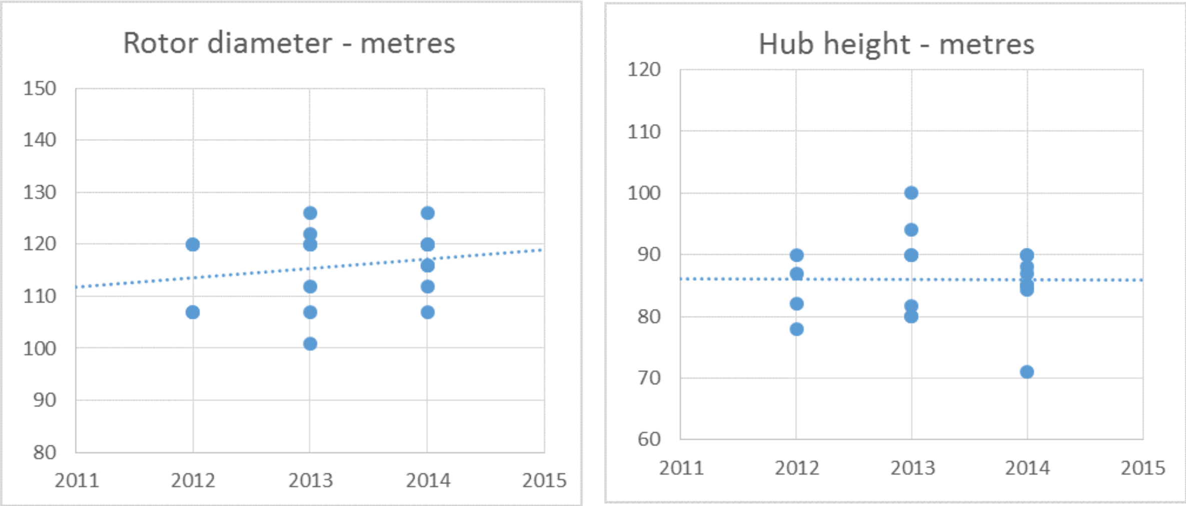

Figure A-2: Range of rotor diameter and hub height by year

The hub height ranged from a minimum of 78m at Greater Gabbard (UK) (2012) to a maximum of 100m in two UK wind farms, Links (2013) and Westermost Rough (2015).

Two physical characteristics of the sites, average water depth and distance to shore, showed an overall increase throughout the period, as shown in Figure A-3.

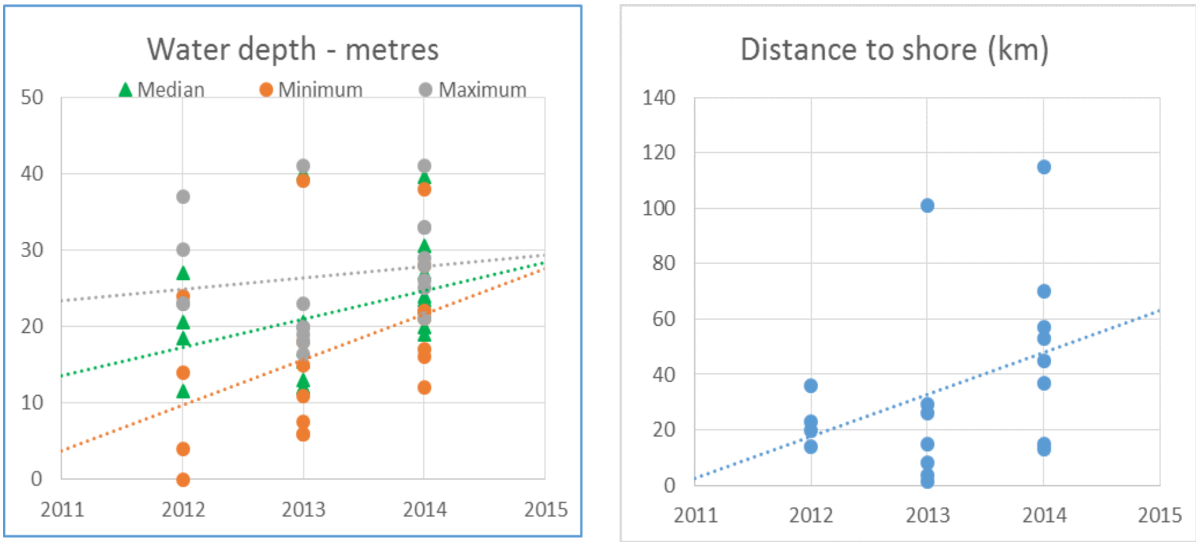

Figure A-3: Spread of water depth and distance to shore by year

The average water depth of the wind farm medians was 21.8m, whereas the weighted average was slightly lower at 21.4m. The shallowest median corresponds to London Array with a median of 11.5m, whereas the deepest median was at Bard Offshore I and Global Tech I, both in Germany, at 40m. The minimum wind farm depth declared was 0m at London Array, but this depth is not suitable for vessel installation. The maximum was 41m at both Bard Offshore and Global Tech I.

Distance to shore also increased with time. Overall for the period, the minimum distance was at Teesside (1.5km) and the maximum at Global Tech I (115km) with an average 35.9km.

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Finally, the most popular type of foundation was the monopile with 1,197 installed out of 1,509 total. Based on the number of foundations, monopiles covered 79% of the demand whereas tripods, jackets, tripile, and gravity-based foundations covered the rest with 120, 96, 80, and 16 units, respectively, as shown in Figure A-4.

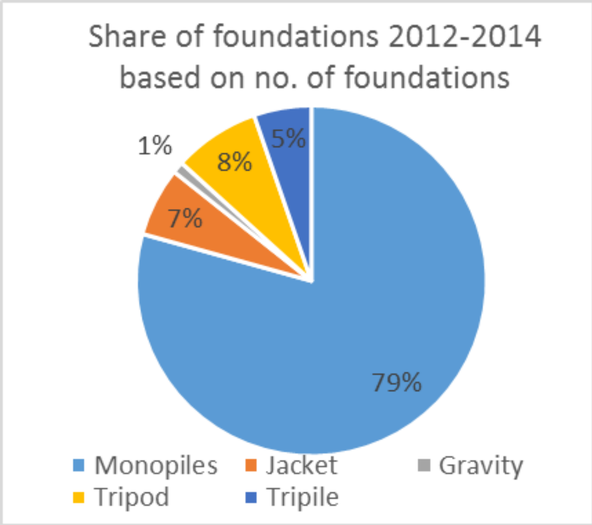

Figure A-4: Foundation type split 2012–2014

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Appendix B. Generic 4MW Power Curve Rev. 2

The data underlying the Rev. 2 curve included in the baseline are shown in Table B-1.

Table B- 1: Generic 4MW Power Curve Rev 2 Data

Wind Speed (m/s)	Rev. 2 Power Curve (MW)
0	0
1	0
2	0
3	42
4	187
5	403
6	709
7	1,127
8	1,675
9	2,372
10	3,122
11	3,799
12	4,000
13	4,000

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Appendix C. Detailed O&M Modelling Comparison

This appendix describes in more detail how the results reported here for the wind farm availability and the O&M costs have been derived. These have been calculated using two O&M models, which are described briefly in Section C.1. Common input data assumptions specified for these models are detailed in Section C.2; some key assumptions are also provided in Section 4.4 of the main document. These inputs could not be represented entirely equally in the models, and differences in how assumptions are represented are explained in Section C.3. Finally, the results from the models are presented in Section C.4 in more detail than in Section 5.3 of the main document and compared. The results used for the baseline LCOE calculation are the average values of results from the two models.

C.1 O&M Models

Two different models have been used for estimating wind farm availability and the O&M cost breakdown:

- NOWIcob model
- ECN (Energy Research Centre of the Netherlands) Offshore Wind O&M Tool.

The NOWIcob model is a discrete-event Monte Carlo simulation model for analysing offshore wind farm O&M and logistics strategies. It has been developed by SINTEF and is described in Hofmann and Sperstad (2013) and Hofmann et al. (2015). The O&M analyses were conducted by SINTEF using the NOWIcob model. The ECN O&M Tool is an Excel-based strategic planning tool and is described in Obdam et al. (2011). NREL carried out the O&M analyses using the ECN O&M Tool. Table C-1 gives an overview of the models and compares their capabilities.

Table C-1: Overview of O&M Models

	NOWIcob	ECN O&M Tool
General modelling philosophy	Analyses offshore wind farm O&M and related logistics, capturing system effects over multiple years of the operational phase	Focused on estimating expected long-term average costs based on historic weather data and repair strategies defined by the user
Model strengths	• Relatively accurate modelling of vessel logistics • Multiple Monte Carlo iterations over time-domain simulation runs for quantifying variability • Captures weather-related dynamics	• Instantaneous results/feedback (without system optimisation) • Flexibility in the inputs that the user can control allows modelling of unconventional scenarios
Model limitations	• Relatively long computation times; • Not primarily used as an O&M cost calculator	• Due to calculating long-term averages the model has simplistic modelling of aspects of O&M • Flexibility of inputs has a time requirement for specifying many modelling assumptions

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C.2 O&M Input Data Assumptions

In this section we state in detail the values assumed for the input parameters of the O&M models. In the following subsections we present tables for maintenance vessels and for maintenance tasks and add comments where necessary to define the entries in the tables.

C.2.1 Vessels

Properties for the various types of vessel are summarized in Table C-2.

Table C-2: Summary of Vessel Properties

Maintenance type	Vessel speed [knots]	Transfer time [minutes]	Technician space	Day rate [€]	Mob. time[a] [days]	Mobilisation cost [€]	Significant wave height limit [m]	Wind speed limit [m/s]
Standard crew transfer vessel (CTV)	22	22	12	3,500	n/a	n/a	1.8	16
Jack-up vessel	7	n/a	n/a	140,000	60	500,000	2	11
Diving support vessel (DSV)	16	n/a	n/a	75,000	15	225,000	2	n/a
Cable laying vessel (CLV)	14	n/a	n/a	100,000	30	550,000	1	n/a

[a] Mobilisation time shown includes lead time waiting for a vessel to be available on the market for the sort of short-term on-demand charters assumed here.

A standard CTV is a conventional, but fairly robust, CTV. It is characterized by turbine access via a "step across" method ("bump and jump"), limited deck space for spare parts and equipment, and a generally SWATH (small waterplane area twin hull)-type hull. The wind speed limit is for transferring technicians to and from the turbine. The CTV day rate estimate is based on NREL's and SINTEF's experience of approximately 2,000–3,500 €/day, including fuel cost. A value in the upper part of this interval is chosen to represent a CTV with a relatively optimistic value of the limiting significant wave height for access (1.8m instead of the more conventional 1.5m). The limiting significant wave height (Hs) should be understood as a limiting value averaged over sea states (characterised by wave direction, wave period, swell, current, etc., in addition to Hs) where transfer of technicians from the vessel to a turbine is possible and safe. Typically, the wind speed is not the limiting factor for turbine access, but the value 16m/s is chosen as an approximate limit for the hub-height wind speed; typical limits for the sea level wind speed of 12m/s are found in the literature (Maples et al. 2013).

The transfer time is the average time needed for transfer of technicians from a vessel to a wind turbine or vice versa. This includes travel within the wind farm (on average 5 rotor diameters of travel from one random position in the farm to another for 100 turbines, giving 7 minutes of travel for each transfer), approaching and docking to the turbine (5 minutes), transferring the technicians (5 minutes for transferring two or three technicians), and lifting/hoisting of small parts or consumables (5 minutes). These time durations are based on SINTEF's industry experience. In the modelling, the same time is assumed to be required for picking up the technicians as for deploying them to the turbine, i.e., there is twice this contribution for each turbine for one shift.

The jack-up vessel is meant to represent a mid-sized to large self-propelled jack-up vessel with a medium-to-large-capacity crane capable of servicing a 4MW turbine. The day rates for jack-up vessels, CLVs, and DSVs are meant to represent long-time averages of the day rate for one-off charters for corrective maintenance ("fix-on-failure"), averaging over relevant vessel types, possible vessel providers, contract designs, times of the year, etc. Fuel cost is assumed to be covered by the day rate.

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The heavy lift vessel (HLV) day rate and mobilisation cost assumptions are based on NREL's and SINTEF's experience, and are consistent with, but somewhat lower, than those of Dinwoodie et al. (2015). The CLV and DSV day rates and mobilisation costs are based on Maples et al. (2013). The mobilisation time is the same as that assumed in Dinwoodie et al. (2015) and somewhat larger than the values stated in Maples et al. (2013). Mobilisation time is here understood as the total length of time from when the need for the vessel is identified to the ordered vessel becoming available in the wind farm, including waiting for a vessel to become available on the market, travel time to the maintenance base of the wind farm, waiting for it to be re-equipped, etc. In reality this value will be associated with huge variability and depends on time of the year, location of the wind farm, type of vessel needed, charter strategy, negotiation details (and day rate, etc.). The value of approximately 2 months is regarded as fairly optimistic but not unreasonable for short-time charters in the European market.

For the jack-up vessel, the significant wave height limit is for jacking up and down, and wind speed limits are for crane use. In Maples et al. (2013), the value 2.5m is used, and NREL and SINTEF industry experience suggests values in the approximate range of 1.2 to 2.8m, depending on vessel operating capabilities. The limiting wind speed 11m/s for lifting represents an average of a 10m/s limit for blade lifting and a limit of 12m/s or above for the lifting of nacelle components. The more pessimistic value 10m/s was used in Maples et al. (2013) and Dinwoodie et al. (2015).

C.2.2 Corrective Turbine Maintenance

The failure data set given in Table C- 3 is based on an industry/consultancy data set expected for new turbines (around 6MW) aggregated to a small number of high-level maintenance tasks. These maintenance data were also used in Dinwoodie et al. (2015). Descriptions of the maintenance tasks and how the data set has been adjusted are given in Table C- 3.

Table C- 3: Turbine Failure Data

Maintenance type	Expected number of annual events	Repair time [h]	Number of technicians required	Material Costs Relative to Turbine Investment Costs (%)	Cost (€)	Vessel requirement
Manual resets	5	3	2	0.004%	238	CTV
Minor repair	3	7.5	3	0.090%	5,279	CTV
Major repair	0.3	22	4	0.500%	29,230	CTV
Major replacement	0.11	34	0	7.550%	441,373	HLV
Remote reset	7	2	n/a	0.000%	–	n/a

Manual resets are brief visits to inspect and/or reset the turbine, possibly involving some consumables or routine replacements. The failure rate of 7.5 per turbine per year reported in Dinwoodie et al. (2015) has been reduced to represent the assumption that turbine resets have been and will continue to be shifted from manual resets to remote resets, based on feedback from Fraunhofer IWES.

Minor repairs are relatively small repairs involving only a small crew and small spare parts that can be lifted by the nacelle-mounted crane. It is assumed that three technicians are needed for safety and complementarity of skills instead of just two as assumed in Dinwoodie et al. (2015).

Major repairs are large repair and component replacement operations taking longer time and involving a larger crew, but needing relatively small spare parts. Specifications for this maintenance task are based on the task referred to as "medium repairs" in Dinwoodie et al. (2015), but contributions of the task there referred to as "major repairs" are also included. The task referred to as "major repairs" in Dinwoodie et al. (2015) required chartering service operation vessels and has been removed from the current data set since the number of tasks using service operation vessels instead of jack-up vessels is assumed to be negligible.

Major replacement is the replacement of large components, requiring jack-up vessels. (The crew will mostly be working from the jack-up vessel and are included in the daily rate of the jack-up vessel.) The failure rate is based on the value of 0.08 in Dinwoodie et al. (2015) and has been increased for the following reasons: 1) to remove the assumption of no gear box failures for a direct-drive turbine concept (increase of ~0.01 for baseline); 2) to assume a less optimistic strategy for preventive component replacements (increase of ~0.01 for baseline); and 3) to include contributions from the maintenance task referred to as "major repairs" in Dinwoodie et al. (2015) where in practice a jack-up vessel would be required. The current figure of 0.11 is still a fairly optimistic estimate, but assumes conventional prognostics capabilities and replacement strategies so that most replacements are not carried out preventively. The repair time was reduced from the previous value of 52 hours (Dinwoodie et al. 2015) based on TKI industry experience.

Remote resets are when the turbine is reset remotely from the control centre. The consequence is only some downtime for the turbine; no visit by technicians is needed. The failure rate of seven per turbine per year of Dinwoodie et al. (2015) has been increased to represent the assumption that turbine resets have been and will continue to be shifted from manual resets to remote resets.

C.2.3 Corrective Inspection

Corrective inspections are performed as a consequence of turbine alarms/warnings where it turns out that a more extensive repair or replacement operation is necessary. This is the case for major repairs and major replacements, and these maintenance tasks are scheduled after completion of the corresponding pre-inspection, as detailed in Table C-4.

Table C-4: Turbine Corrective Inspection Data

Maintenance type	Expected number of annual events	Repair time [h]	Number of technicians required	Cost (€)	Vessel requirement
Pre-inspection for major repair	0.3	7.5	2	-	CTV
Pre-inspection for major replacement	0.11	7.5	2	-	CTV

C.2.4 Preventive Maintenance

Annual turbine service includes inspections and general turbine upkeep. In this maintenance task, we have in addition included the averaged effect of major overhauls and happening at intervals of 5–12 years as well as miscellaneous inspections outside the turbine where the turbine needs to be shut down. Maintenance data for annual services are based on Dinwoodie et al. (2015) and reduced by 10 hours based on SINTEF industry experience to indicatively represent a 4–5MW turbine. (Sixty hours and possible four technicians could be more representative for a 5–6MW turbine and above.)

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Assumptions for inspections of BoS components are approximate and aggregate a number of different inspection types, based on SINTEF's industry experience. The preventive maintenance data are summarized in Table C-5.

Table C-5: Preventive Maintenance Data

Maintenance type	Expected number of annual events	Repair time [h]	Number of technicians required	Material Costs Relative to Turbine Investment Costs (%)	Cost (€)	Vessel requirement
Annual service of turbine	1	50	3	0.075%	4,385	CTV
Substation inspections	4	30	3	0.000%	-	CTV
Structure inspections	1	4	2	0.000%	-	CTV

C.2.5 Corrective BoS Maintenance

Corrective maintenance data and cost data for BoS components are in part based on default ECN O&M Tool values; see also Maples et al. (2013). ECN O&M Tool values were modified to reflect the number of turbines and transformers used in the wind farm

For the small foundation / scour protection repair, the turbine does not need to be shut down during maintenance. The failure rate is given per turbine.

For the small and large transformer repairs, faults shut down half the wind farm. The failure rate is for each of the two transformers in the single offshore substation.

For the cable replacement, cable failure rates are given per turbine and are based on the ECN O&M Tool/NREL estimate of an annual failure rate of 0.05 for a wind farm of 130 turbines. We assume that a fault on the cable for a given turbine on average shuts down six turbines. Table C-6 summarizes the corrective BOS maintenance data.

Table C-6: Corrective BoS Maintenance Data

Maintenance type	Expected number of annual events	Repair time [h]	Number of technicians required	Cost (€)	Vessel requirement
Small foundation / scour protection repair	0.023 per turbine	8	0	5,000	DSV
Small transformer repair	0.45 per transformer	8	3	5,000	CTV
Large transformer repair	0.05 per transformer	48	4	250,000	CTV
Cable replacement	0.0004 per turbine	32	0	350,000	CLV

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C.2.6 Metocean Data

The same wind and wave time series from the site of Horns Rev 3, as described in Section 4.1, are used for both models. The NOWIcob model has the capability of generating multiple synthetic time series to use in the Monte Carlo simulation, but this functionality was not enabled for this work. Since 20-year wind speed and significant wave were needed for the O&M modelling, the 11-year time series (January 2003 – December 2013) were repeated twice to get the sufficient length; only the first 20 years of the resulting time series are used. The time resolution of the time series is one hour. Gaps in the wind data (119 entries) were replaced by mean values for the remaining time series.

C.3 O&M Scenario Representation

Due to differences in modelling approach and functionalities between the NOWIcob model and the ECN O&M tool, the same baseline scenario is necessarily represented somewhat differently in the two models. A comparison of the modelling assumptions is given in Table C-7. We also state some assumptions that are represented in a similar manner in the two models.

Table C-7: Comparison of O&M Model Assumptions

Parameter	NOWIcob	ECN O&M Tool
Number of CTVs	Given as input to the model: three CTVs (constant during the year)	Used the model to estimate needed CTVs to complete repairs: two CTVs (constant during the year)
Number of technicians	Given as input to the model: 30 technicians (constant during the year)	Used the model to estimate needed technicians to complete repairs: 22 (ranged from 15–30 depending on the season)
Impact of charter duration	It is assumed that vessels chartered to the wind farm are available for a fixed charter duration: HLV – 20 days; DSV – 4 days; CLV – 10 days; this may contribute to overestimating charter costs	The ECN O&M Tool does not have the capability to model charter durations due to estimating long-term averages
Vessel rates for waiting times	Charter costs are incurred for the entire charter duration irrespective of whether the vessel is working or waiting (for weather or otherwise)	75% of the daily rate for HLV, based on the default ECN O&M Tool value
Jack-up vessel operational phases	Major replacement operations are modelled as consisting of: 6-hour jack-up phase (only wave limits enforced); 24-hour lifting/repair phase (only wave limits enforced);	Major replacement operations are modelled as consisting of a 34 hour repair (both wave and wind limits enforced);

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Parameter	NOWIcob	ECN O&M Tool
	4-hour jack-down phase (only wave limits enforced)	Repairs occur over 2 x 11-hour shifts per day, not a single 11-hour shift
Splitting of jack-up vessel operations	It is assumed that repairs can be split over non-consecutive shifts	
Technicians needed at the turbine for major replacements	It is assumed that no CTVs are needed to transfer technicians to the turbines during major replacement operations	
Waiting times for a weather window	Vessel weather limits represent averages not specific processes during the repair (this applies to each operational phase for Major replacements and to the entire repair task for the other maintenance tasks)	May be over (jack-up vessel) or underestimated (CTVs) CTVs: clustering of multiple repairs, inspections, and annual maintenance reduces wait and travel times. Jack-up vessels: weather limits represents averages not specific processes during the repair
Spread of annual services over the year	The first annual service is started on 1 April, and then one schedules to start annual service for one new turbine each shift. When services are actually done will vary, but typically, most are carried out during the summer months.	25% Spring, 50% Summer, 25% Fall
Substation inspections	Assumed to be all done in June	Assumed to occur roughly every 6 months
Structure inspections	Done from May onwards	Carried out opportunistically throughout the course of the year.
Prioritisation of maintenance tasks	Corrective will always be prioritised over preventive maintenance; transformer repairs will be prioritised over other repairs, all else being equal; smaller maintenance tasks will be prioritised over larger, all else being equal.	The ECN O&M Tool does not prioritise maintenance tasks as it is based on long-term averages.

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Parameter	NOWIcob	ECN O&M Tool
Travel distances within the wind farm	In-farm distance is set to zero, but travel time is included in the transfer time for each turbine visit	

There are also some notable differences in how output parameters are calculated in the two models; a comparison is given in Table C-8.

Table C-8: Comparison of O&M Model Output Parameters

Parameter	NOWIcob	ECN O&M Tool
Time-based availability	Wind farm availability = (turbines availability) x (availability of electrical infrastructure) Effectively assuming no overlapping electrical infrastructure component downtime events	
Energy-based availability	Defined as (amount of electrical energy actually generated over the period) / (theoretical max. of electrical energy generated in the period, given no downtime). Other losses not included in the energy-based availability.	Detailed modelling of energy-based availability not applicable for long-term averages. Results shown here only represent differences in repairs occurring in different seasons
Downtime by repair type	This is calculated independently from the availability, i.e., the latter is not based on the former. The downtime estimates therefore only give an approximation for the contribution from the different repair types. Downtime due to transformer repairs are estimated as transformer downtime times 50; downtime due to cable replacement estimated as by multiplying downtime by 6.	This is calculated based on the availability of the turbines in the wind farm, directly reflecting the contribution from the different repair types
Power curve	Only power curve values for integer-valued wind speeds are used in the model	
Capacity factor	The reported capacity factor was estimated in the model from the power curve and does not include any losses (availability or otherwise)	The reported capacity factor was estimated in the model using the power curve
Energy production	9% wake losses and 4% combined electrical and hysteresis losses are included in estimating electrical energy production	

C.4 Fixed Operations Costs

The non-maintenance costs of operating an offshore wind farm cover a wide scope and typically represent fixed annual costs. These items are typically not estimated by O&M models such as the

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ECN O&M Tool or the SINTEF NOWIcob model because they can vary widely between projects and do not often have a clear relationship with technical project parameters or site input variables. Instead, these values are typically input separately and are based on experience or project-specific quotes. Table C-9 describes the categories that are considered for this analysis and identifies the data sources used to inform cost estimates.

Table C-9: Description of Fixed O&M Costs

Level	Category	Description	Source
2	**Operations**	Non-maintenance costs of operating the project	
3	**Operation, Management and General Administration**	Activities necessary to forecast, dispatch, sell, and manage the production of power from the wind farm. Includes both onsite and offsite personnel, software, and equipment to coordinate high voltage equipment, switching, port activities, and marine activities	Roll-up of below categories
4	**Project management and administration**	Financial reporting, public relations, procurement, parts and stock management, health and safety equipment management, training, subcontracts and general administration.	DNV GL 2013, NREL 2015
4	**Marine Management**	Coordination of port equipment, vessels, and personnel to carry out inspections and maintenance of generation and transmission equipment	DNV GL 2013
4	**Weather Forecasting**	Daily forecast of metocean conditions used to plan maintenance visits and estimate project power production.	DNV GL 2013
4	**Condition Monitoring**	Monitoring of supervisory control and data acquisition data from wind turbine components to optimise performance and identify component faults	DNV GL 2013, NREL 2015
3	**Operating Facilities**	Co-located offices, parts store, quayside facilities, helipad, refueling facilities, hanger (if necessary).	DNV GL 2013, NREL 2015
3	**Environmental, Health, and Safety Monitoring**	Coordination and monitoring to ensure compliance with HSE requirements during operations	DNV GL 2013
3	**Insurance**	Insurance policies during operational period including All Risk Property, Business Interruption, Third Party Liability, and Brokers Fee, and Atlantic Storm Coverage (high end of range only)	NREL 2015
3	**Annual Leases and Fees**	Ongoing payments, including but not limited to: payments to regulatory body for permission to operate at project site (terms defined within lease); payments to Transmissions Systems Operators or Transmission Asset Owners for rights to transport generated power	Roll-up of below categories
4	**Submerge Land-Lease Costs**	Payments to submerged land owner for rights to build project during operations	NREL 2015
4	**Transmission Charges/Rights**	Any payments to Transmissions Systems Operators or Transmission Asset Owners for rights to transport generated power.	Not estimated; market specific
4	**Community Benefit Fund**	One-off or ongoing payments required to local authority or community groups	Not estimated; market specific

Transmission charges have not been estimated for this baseline as these obligations are very market specific. It is expected that future analysis to explore market specific costs will quantify these costs where relevant.

C.5 Detailed O&M results

This section presents output parameters for each of the O&M models for the baseline case and compares them. In addition to output parameters underlying the wind farm availability and O&M cost results, we also present a number of other output parameters used to compare and verify the results from the O&M analysis.

C.5.1 Summary of Availability Results

The maintenance models output availability and cost results. These are summarised in Table C-10.

The O&M results shown are focused on a time-based method of estimating availability. The ECN O&M Tool does a good job of estimating time-based availability (compared to other models), but the version of the tool used is not capable of producing a meaningful energy-based availability. The ECN O&M Tool uses statistics derived from the long-term metocean dataset to estimate lifetime average time-based availability for those repairs. The energy-based availability shown below is related to the ECN O&M Tool estimating long-term seasonal averages. The difference between time-based and energy-based availability is attributable to differences between O&M in each season rather than timing of any individual repairs. The general lack of correlation between availability and wind speed (potential power that can be produced in each time period) means that producing energy-based availability estimates using the ECN O&M Tool is not feasible. A process-based tool more suited to estimating energy-base availability models each step in the repair process according to the metocean conditions in each time period over the project life. An energy-based availability would depend on the timing of the modelling of these process steps.

Table C-10: O&M Modelling Results

Output parameter	Units	NOWIcob	ECN O&M Tool
Availability - Time	%	93.3%	94.9%
Availability - Energy	%	92.6%	94.8%
Total Downtime	day/turbine/yr	26	19
Total Annual Costs	million €/yr	25.4	28.4

Maintenance cost results are summarised by Category of expenditure in Table C-11.

Table C-11: Comparison of Modelled O&M Cost Results

Output parameter	Units	NOWIcob	ECN O&M Tool
Technicians	million €/yr	3.0	2.3
Spare Parts	million €/yr	7.8	7.9
Vessels	million €/yr	14.5	18.2
- Crew Transfer	million €/yr	3.8	1.8
- Jack-up Vessel	million €/yr	9.5	15.5
- Diving Support	million €/yr	1.1	0.9
- Cable Laying Vessel	million €/yr	0.1	0.1

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Downtime by repair category is summarised in Table C-12.

Table C-12: Comparison of Modelled Downtime

Output parameter	Units	NOWIcob	ECN O&M Tool
Manual resets	day/turbine/yr	7	4
Minor repair	day/turbine/yr	7	4
Major repair	day/turbine/yr	2	1
Major replacement	day/turbine/yr	5	6
Remote reset	day/turbine/yr	1	1
Annual service	day/turbine/yr	3	2
BoS	day/turbine/yr	1	1

Resource use for each model is summarised in Table C-13.

Table C-13: Comparison of Modelled Resource Use

Output parameter	Units	NOWIcob	ECN O&M Tool
Crew transfer	# of vessels	3	2
Jack-up	# of vessels	1	1
Diving support	# of vessels	1	1
Cable laying	# of vessels	1	1
Technicians	#	30	23

C.5.2 Summary of O&M Cost Results

O&M costs for the Task 26 baseline project are estimated using a combination of maintenance models (averaging results from ECN O&M Tool and NOWIcob in Table C-14) and market data. Offshore maintenance costs are estimated to total €26.9 million per year on average over the project lifetime. Adding onshore electric maintenance, which is estimated to cost €0.2 million per year, provides an estimate for total maintenance costs of €27.1 million per year. Operations costs, which are derived from market data and industry experience, are estimated at €12.2 million per year on average over the project lifetime. Table C-14 summarises the O&M costs by category of expenditure. Note that all figures are rounded to one decimal place in the table, but totals and subtotals are consistent with the underlying detail.

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Table C-14: O&M Costs Included in Baseline

Level	Category	Baseline Value	Baseline Value
		(€ millions/yr.)	(€/kW/yr)
1	**OpEx**	**39.2**	**97.9**
2	**Maintenance**	27.1	67.7
3	Offshore maintenance	26.9	67.2
4	Technicians	2.7	6.6
4	Spare parts	7.9	19.6
4	Vessels	16.4	40.8
3	Onshore electric maintenance	0.2	0.5
2	**Operations**	12.2	30.4
3	Operation, Management and General Administration	1.1	2.8
4	Project management and administration	0.3	0.8
4	Marine management	0.5	1.2
4	Weather forecasting	0.0	0.1
4	Condition monitoring	0.3	0.8
3	Operating facilities	0.5	1.3
3	Environmental, Health, and Safety Monitoring	0.2	0.5
3	Insurance	8.4	21.0
3	Annual Leases and Fees	1.9	4.8
4	Submerge land-lease costs	1.9	4.8
4	Transmission charges/rights	Not estimated	Not estimated
4	Community benefit fund	Not estimated	Not estimated

Figure C-1 shows the contributions of each element to the OpEx. For all OpEx figures estimated from the O&M models, the bars show the span between the lowest and the highest value of the cost results from the two models. For the fixed operations costs, the bar shows the span between the low estimate and the high estimate, which are based on Task 26 members' experience.

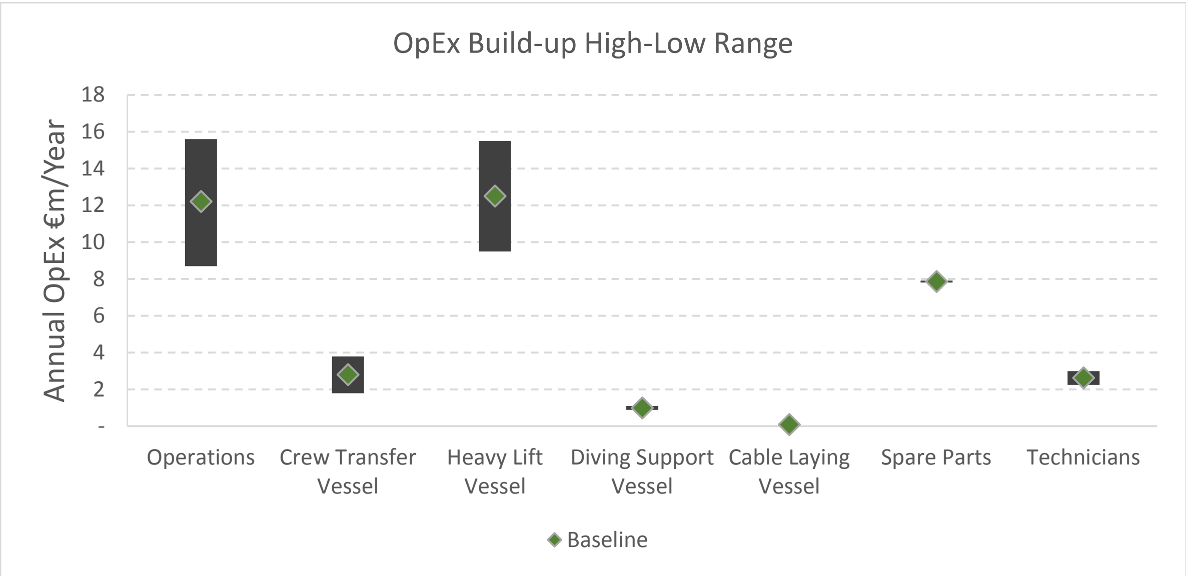

Figure C-1: OpEx breakdown from models used

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The low-value and high-value estimates for the annual OpEx are shown and compared in Figure C-2. For the low-value estimate, the lowest value from the figure above is used for each cost contribution; for the high-value estimate, the highest value from the figure above is used for each cost contribution.

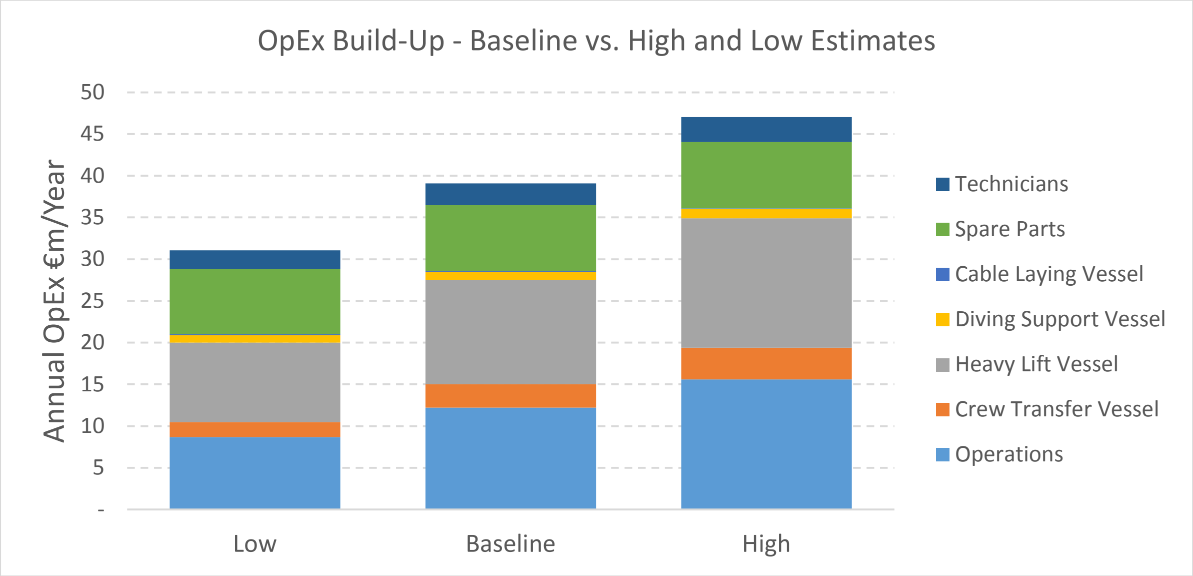

Figure C-2: Comparison of baseline with lowest and highest resulting O&M costs

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