Installation, Operation, and Maintenance Strategies to Reduce the Cost of Offshore Wind Energy

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Technical Report
NREL/TP-5000-57403
July 2013

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List of Acronyms and Abbreviations

AEP	annual energy production
BOP	balance of plant (same as BOS)
BOS	balance of station (same as BOP)
CAPEX	capital expenditures
CBM	condition-based monitoring
CF	construction financing
DEMOB	demobilization
DOE	U.S. Department of Energy
DP2	dynamically positioned
ECN	Energy Research Centre of the Netherlands
FCR	fixed charge rate
FOA	Funding Opportunity Announcement
FTC	fault type class
h	hour
H_s	significant waveheight
ICC	installed capital cost
IO&M	installation, operation, and maintenance
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
L	liter
LCOE	levelized cost of energy
m	meter
MC	maintenance category
MOB	mobilization
m/s	meter per second
MT	metric tonne
MW	megawatt
nmi	nautical mile
NREL	National Renewable Energy Laboratory
OCC	overnight capital cost
O&M	operation and maintenance
OPEX	operation expenditures
RDS-PP	reference designation system for power plants
ROI	return on investment
ROV	remotely operated vehicle
TCC	turbine capital cost
USD	U.S. Dollar
V_w	wind velocity
WeWi	weather window
WindPACT	Wind Partnerships for Advanced Component Technology
WT	wind turbine

Executive Summary

This report is intended to provide offshore wind industry stakeholders a basis for evaluating potential cost saving installation, operation, and maintenance (IO&M) strategies and technologies. The work was completed by the National Renewable Energy Laboratory (NREL) and its subcontractor, the Energy Research Centre of the Netherlands (ECN), in fulfillment of a U.S. Department of Energy (DOE) contract for subtopic 5.3: Optimized Installation, Operation, and Maintenance Strategies under topic 5: Optimized Infrastructure and Operations of Funding Opportunity Announcement (FOA) number DE-FOA-0000414, entitled "U.S. Offshore Wind: Removing Market Barriers." For stakeholders carrying out project-specific evaluations of IO&M approaches presented herein, several related studies also conducted under this FOA will serve as valuable resources on specific aspects of offshore wind development infrastructure including ports, vessels, and supply chain parameters.

Some of the IO&M strategies in this report were analyzed without projecting the capital expenditures associated with an enabling technology or method. Thus, the results show the upside or added value to a strategy (e.g. increased energy production), and not the potential downside (e.g. added capital cost of new hardware). The results of the analysis can therefore be used by industry stakeholders to take the cost savings presented in this report and add their revised technologies costs to arrive at a net decrease or increase in cost of energy resulting from a proposed IO&M strategy. This allows many technologies that target the same improvement area to be evaluated subsequent to this study. To clarify this concept, an example is presented below.

> Company X is interested in bringing an innovative vessel capable of operating at higher wind and wave conditions to market. If a strategy using an innovative vessel capable of operating in higher wind and wave conditions (similar to Company X's design) is shown to reduce costs by $100/kW with respect to the baseline, Company X can see that in order to be viable in the market, they must be able to deliver their innovative vessel at a rate no more than $100/kW greater than the vessel rate used in the baseline. If Company X can deliver their innovative vessel at $25/kW more than the baseline, they will have demonstrated that their new vessel technology is capable of saving $75/kW with respect to the baseline.

Introduction

IO&M is expected to account for nearly one-third of offshore wind levelized cost of energy (LCOE) in the United States (U.S. Department of Energy, 2011). Consequently, there is a large potential for reducing LCOE through advanced IO&M strategies. NREL and ECN, along with a panel of subject matter experts who provided input, have used their offshore wind cost modeling capabilities to fulfill the project's two primary objectives:

- Conduct analysis and modeling to identify the most practical means of reducing offshore wind LCOE through advanced IO&M techniques, integrated service providers, and preferred supporting infrastructure.
- Identify preferred IO&M strategies in a case study of a hypothetical U.S. offshore wind project.

To accomplish the objectives related to installation costs, NREL has developed a new offshore wind turbine installation cost module which, coupled with the NREL offshore wind plant balance of station (BOS) model, is capable of analyzing many scenarios including the six (6) turbine assembly strategies and three (3) additional project installation strategies that this study analyzes.

To accomplish the objectives related to O&M costs, ECN has established an O&M tool for the U.S. offshore market based on their industry-leading offshore wind operation and maintenance (O&M) planning software, the *ECN O&M Tool v.4* (Obdam, Braam, & Rademakers, 2011). This tool has been used to identify the O&M cost implications of six (6) O&M strategies for this study.

For the analysis, we used real-world wind and wave condition data, but parameters such as project size (500 MW), turbine size (5 MW), and location (46 km off the coast of Virginia) were chosen to represent a typical but hypothetical utility-scale offshore wind plant. This study does not attempt to represent an existing wind plant, or a wind plant currently under development. The same holds true for the realistic but hypothetical reference wind turbine used in this study.

To demonstrate the impacts of the strategies investigated, the analysis has been divided into three (3) sections: baseline, advanced IO&M strategies, and preferred case study.

- (Chapter 3) The baseline section establishes a reference project, IO&M strategy, and cost for use in further comparisons.
- (Chapter 4) The advanced IO&M strategies section investigates individual IO&M strategies and demonstrates their impact on system LCOE.
- (Chapter 5) Finally the preferred case study section applies the most impactful combination of those advanced IO&M strategies to the hypothetical offshore wind plant in order to present a preferred overall IO&M approach for that facility.

Baseline

The baseline installation strategy resulted in a total installation cost of $633 million dollars for the 500MW project. Vessel costs accounted for the majority of the total installation costs. The baseline O&M scenario yielded an availability of 84.5% and O&M costs of $0.0283/kWh. The majority of downtime is associated with corrective maintenance on the wind turbine and balance of plant structures. Table 1 illustrates that roughly 12% of the baseline LCOE is attributable to O&M and 20% to installation activities (installation vessels + ports and staging).

Table 1. Summary of Baseline LCOE

	($/kW)	($/kWh)
Turbine Capital Cost	1800	0.0650
Development	*118*	*0.0043*
Port and Staging	*26*	*0.0009*
Support Structure	*800*	*0.0289*
Electrical Infrastructure	*498*	*0.0180*
Installation Vessels	*1240*	*0.0448*
Balance of Station	2682	0.0969
Insurance	*90*	*0.0033*
Decommissioning	*471*	*0.0170*
Contingency	*448*	*0.0162*
Soft Costs	1009	0.0364
Overnight Capital Cost (OCC)	5491	0.1983
Construction Financing	*165*	*0.0060*
Installed Capital Cost (ICC)	5656	0.2043
O&M ($/kW/yr)	784	0.0283
Net Annual Energy Production (AEP) (MWh/MW/yr)	3267	
Fixed Charge Rate (FCR)	11.8%	
Levelized Cost of Energy ($/kWh)	**0.233**	

Advanced IO&M Strategies

At the onset of the project, a panel of subject matter experts (listed in Section 4) was gathered to brainstorm a list of potential advanced IO&M strategies. This set of strategies was down-selected based on three criteria explained in Section 4, to those listed in Table 2 for further analysis.

Table 2. IO&M strategies investigated

Installation Strategies	**O&M Strategies**
Land-based vs. offshore assembly	Mother vessel accommodations
Direct delivery of components	Helicopter access
Purpose-built installation vessel	Fixed vessel contracts
Reduced electrical and foundation installation	Improved crew transfer system
	Spare part storage
	Advanced condition-based monitoring (CBM)

Installation

A set of six (6) turbine assembly strategies, reflecting varying degrees of land-based vs. offshore assembly, and four (4) additional project installation strategies were analyzed in this study. The analyses of foundation and electrical strategies were conducted as sensitivity analyses wherein the primary cost driver was varied higher and lower by a prescribed amount. The other installation analyses were designed to demonstrate the impact of a specific technology or approach. Figure 1 demonstrates the relative impact of each installation strategy with respect to the baseline installed BOS cost (BOS + insurance + contingency + construction financing), whether it be a sensitivity analysis (foundation and electrical) or an analysis of a particular technology or approach (purpose built vessel, component delivery, and turbine assembly).

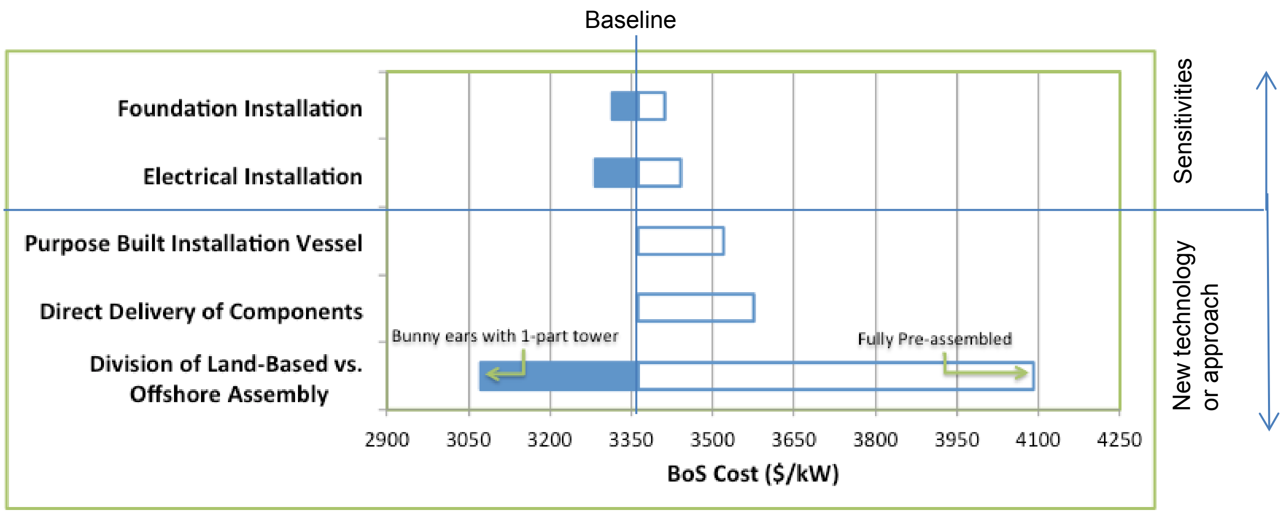

Figure 1. Impact of installation strategies investigated

The strategies varying the degree of assembly carried out on land, versus offshore, have the potential to make the biggest impact on BOS cost, either reducing it by almost $300/kW compared to the baseline, or increasing BOS cost by approximately $650/kW. The strategy of arranging direct delivery of components to the project site (bypassing a staging port) increases the BOS cost compared to the baseline, as does the use of a purpose-built installation vessel, under this set of assumptions. Changes to the foundation installation duration would have the smallest impact on BOS costs compared to the baseline, and innovations affecting the electrical installation could have a slightly larger impact (either increasing or decreasing total BOS costs, depending on whether the innovation increased or decreased the electrical costs).

O&M

Table 3 summarizes the results of each of the O&M strategies investigated. As discussed further in Section 5 of the report, even though many of the strategies show promise for reducing LCOE, the benefits could overlap when implemented together (i.e., the improvements to LCOE may not be additive and the overall cost of implementing several strategies may exceed the benefit of reduced LCOE).

Table 3. Quantitative summary of the O&M strategies investigated

O&M strategy summary	Main strategy change compared to baseline	Availability [%]	O&M Costs [$/kWh]	Total yearly effort [M$][1]	Result notes
Baseline O&M scenario	–	84.5	0.0283	86.9	Investment and operational costs for onsite storage are not accounted for in the baseline.
Mother vessel accommodation	Reduced travel time from 2.6 h to 0.5 h. Small parts in stock at mother vessel	91.2	0.0224	62.0	Analysis does not account for mother vessel investment and operations costs. [indication: $15M - $20M/year when rented from spot market, (BVG Associates, 2012)].
Helicopter access	Reduced travel time from 2.6 h to 1.0 h. Only for small repairs without spare parts.	87.1	0.0290	82.9	Includes estimated helicopter costs. Does not account for additional turbine investment costs for landing platform.
Vessel contracts	*Parameter study:* Jack-up vessel contract Logistics time: 0 – 2200 h MOB/DEMOB costs: 0 – 880 k$	83.0 – 85.0	0.0245 – 0.0362	82.3 – 99.4	Assuming clustering of large repairs, a fixed contract is only favorable in scenarios when costs per MOB/DEMOB can be lowered significantly.
Improved crew transfer system	*Parameter study:* Access vessel limits Wave height: 0.7 – 3.0 m Wind speed: 12 & 16 m/s	61.3 – 95.3	0.024 – 0.044	56.2 – 153.0	Wave height limit of workboats has large influence on availability and costs. Wind speed limit has very limited influence. Wave height limits greater than 1.7 m has minimal impact on costs.
Spare part storage	*Parameter study* Vary logistics time of part delivery for Maintenance Category (MC) 4 (MC4) repairs: 0 – 336 h	82.3 – 84.5	0.0283 – 0.0290	86.9 – 92.2	Longer logistics times lead to additional costs compared to baseline (i.e., small parts are stored onsite).
Advanced CBM	*Parameter study* Assume Advanced Condition-Based Monitoring (CBM) for MC4 and MC6 which are subsequently preventively replaced. Detection rate: 0 – 100%	84.5 – 86.9	0.0274– 0.0283	80.4 – 86.9	If a larger percentage of failures can be detected by advanced CBM systems the availability increases and cost decreases. Analysis did not account for investment and operational costs for advanced CBM systems. Additional costs due to false alarms not considered.

[1] Total O&M effort numbers presented in this report represent the sum of revenue losses and accrued O&M costs on a yearly basis. The $/kWh O&M costs, however, do not include the direct cost of revenue losses. Rather, the impact from loss of revenue on a $/kWh basis is accounted for via the change in energy production.

The two O&M strategies with the highest potential to improve availability and reduce revenue losses are: investment in an improved crew transfer system (e.g., application of a workboat with less restrictive weather limitations) and using a mother vessel to provide accommodation at the wind plant instead of daily transfer from the harbor. Both strategies focus on a reduction of the waiting time caused by bad weather conditions, which is the primary driver for the low wind plant availability in the baseline scenario. Individually, each of these strategies has the potential to reduce the total O&M effort from the baseline by more than $20 million. Other O&M strategies (helicopter access and advanced CBM) also yielded improvements, albeit much smaller than for the improved crew access system and mother vessel accommodation. On the other hand, ordering spare parts directly from the factory, rather than storing them onsite, causes longer downtimes and could decrease availability compared to the baseline.

Preferred IO&M Case Study

For the preferred IO&M case study we:

- Analyzed combined installation strategies to establish a preferred installation strategy
- Analyzed combined O&M strategies to establish a preferred O&M strategy
- Assessed the tradeoffs between O&M costs, associated installation costs, and energy production impacts to establish a preferred IO&M strategy.

Installation

As reported above, of the installation strategies that we investigated, only two showed potential cost reductions compared to the baseline: division of turbine assembly tasks between onshore and offshore; and changes to foundation and electrical installation approaches. Since we did not identify specific foundation or electrical installation technologies or process innovations, we did not include changes in these areas in our preferred installation strategy.

Although the "bunny ears with 1-part tower assembly" method was potentially the lowest cost option, some turbine manufacturers may not allow the bunny ears method because transportation of the turbine in that unique configuration could lead to increased, or at least uncertain, loads on components. Consequently, the bunny ears style installation method was ruled out for the preferred case. The next lowest-cost assembly strategy was the "pre-assembled rotor with one part tower", which we selected as the preferred installation strategy.

O&M

The majority of the O&M strategies aim to increase availability by reducing waiting time; therefore, the preferred O&M strategy analysis was completed in a multi-step approach where one strategy was applied (e.g., *improved crew transfer*) and then a second (or more) strategy(s) (e.g., *helicopter access*) was added on top of the first. Table 4 summarizes the most impactful combined O&M strategies investigated under this approach.

Table 4. Summary of O&M strategies studied with highest improvement opportunity

O&M strategies	Availability [%]	O&M Costs [$/kWh]	Total yearly effort [M$][2]	Result notes:
Baseline O&M scenario	84.5	0.0283	86.9	This is the baseline O&M scenario
Step 1: Improved crew transfer	**93.3**	**0.0248**	**62.1**	**Significant effect compared to baseline: total O&M decreased by $24.8M.**
Step 1 + Variation A: Mother vessel	95.2	0.0223	53.3	Analysis does not account for increased cost of mother vessel [indication: $15M - $20M/year when rented from spot market, (BVG Associates, 2012)].
Step 1 + Variation B: project-owned jack-up vessel	93.8	0.0180	48.8	Accounts for changes in operating expenses, but not capital cost of project-owned jack-up vessel.
Step 1 + Variation C: Helicopter access	93.9	0.0260	63.3	Increased operational costs. Does not account for additional turbine investment costs for landing platform.
Step 1 + Variation D: Advanced CBM	93.7	0.0247	61.1	Results shown are for 50% detection rate with 0% false alarms. Does not account for investment and operational costs for advanced CBM systems.

IO&M

The preferred IO&M strategy for the case study would utilize a turbine installation procedure whereby the rotor would be pre-assembled in port before load-out for offshore installation. Additionally, the tower for the turbine would be completely assembled in port so that only a single offshore lift is necessary for its installation. The preferred IO&M strategy for the case study also included advancement in O&M where an improved U.S. work boat for crew transfer is used. This improved work boat reduced the waiting time caused by weather by increasing the allowable working sea state for average U.S. work boats from a significant wave height of 0.9 m to 1.5 m. Based on the wind and wave conditions at the hypothetical case study location, increasing the allowable sea state for work boats beyond 1.5 m would not provide significant impact on LCOE.

Through the changes implemented in the preferred case study, a number of improvements were made to the LCOE. The changes to the turbine installation strategy had a mixed impact; ports and staging costs increased while installation vessel costs decreased. The nearly tripling in ports and staging costs is primarily a result of the increased storage area needed for the pre-assembled

[2] Total O&M effort numbers presented in this report represent the sum of revenue losses and accrued O&M costs on a yearly basis. The $/kWh O&M costs, however, do not include the direct cost of revenue losses. Rather, the impact from loss of revenue on a $/kWh basis is accounted for via the change in energy production.

rotors. The improved assembly strategy, however, reduced the vessel costs by $185/kW (15%), which far outweighs the increase in port and staging costs.

Overall O&M costs were lowered by $0.0035/kWh (12%), primarily because the increased sea state limits allowed for significantly reduced waiting periods. This reduction in waiting time has a substantial impact on the energy production, raising availability from 84.5% to 93.3%, an increase of nearly 12% or 381 MWh/MW per year. This increase in annual energy production (AEP) is the primary contributor to the overall reduction in LCOE seen in Table 5.

Table 5. Improvements in LCOE through the preferred IO&M strategy

	Baseline	Preferred	Impact
AEP (MWh/MW/yr)	3267	3648	+11.7%
Availability (%)	84.5	93.3	+10.4%
O&M ($/kWh)	0.0283	0.0248	-12.4%
Ports & Staging ($/kW)	26	79	+304%
Installation Vessels ($/kW)	1240	1055	-15%
LCOE ($/kWh)	**0.233**	**0.200**	**-14%**

The IO&M improvements resulted in a sizable reduction in the overall LCOE for the case study. A change in turbine installation strategy combined with an improved work boat decreased the LCOE for the preferred case study from a baseline of $0.233/kWh to $0.200/kWh. This 14% reduction in LCOE is primarily attributable to the increase in AEP and is a strong indicator that careful planning and analysis of IO&M strategies can significantly reduce LCOE.

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1 Introduction

This document summarizes the work completed by the National Renewable Energy Laboratory (NREL) and its subcontractor, the Energy Research Centre of the Netherlands (ECN), in fulfillment of a U.S. Department of Energy (DOE) contract for subtopic 5.3: Optimized Installation, Operation, and Maintenance Strategies under topic 5: Optimized Infrastructure and Operations of Funding Opportunity Announcement (FOA) number DE-FOA-0000414, entitled "U.S. Offshore Wind: Removing Market Barriers." For those carrying out project-specific evaluations of cost-effective IO&M approaches presented herein, several related studies also conducted under this FOA will serve as valuable resources on specific aspects of offshore wind development infrastructure including ports, vessels, and supply chain parameters.

1.1 Disclaimer

This study does not represent an existing wind plant, or a wind plant currently under development. The same holds true for the reference wind turbine used in this study. All data used in this study (among others: failure data, vessel capabilities and costs, repair strategies and wind turbine specifications) are relative and should not be taken as facts. Although the authors have attempted to use figures that are representative of contemporary large offshore wind plants, readers must always use their own data, applicable to their own situation. However, the data in this document can be used as a starting point with the relative changes associated with each strategy providing useful insight into overall trends.

1.2 Background

The DOE National Offshore Wind Strategy guides the national effort to reduce the levelized cost of energy (LCOE) and deployment timelines for future offshore wind power projects (U.S. Department of Energy, 2011).

Currently, installation, operation, and maintenance (IO&M) costs are expected to account for approximately 30% of the LCOE of offshore wind plants in the United States (U.S. Department of Energy, 2011). The National Renewable Energy Laboratory (NREL) along with its proposal partners, hereafter referred to as the Team, were granted an award by DOE under FOA DE-FOA-0000414 to use the offshore wind cost model capabilities developed at NREL, along with the operating experience and O&M modeling capabilities of the rest of the Team, to meet the following main project objectives:

- Conduct analysis and modeling to identify the most practical means of reducing LCOE and ensuring safety through advanced IO&M techniques, integrated service providers, and preferred supporting infrastructure
- Identify preferred IO&M strategies in a case study of a hypothetical U.S. offshore wind project.

This report is intended to provide industry stakeholders a basis for evaluating potential cost saving installation, operation, and maintenance (IO&M) strategies and technologies. Some of the IO&M strategies in this report were analyzed without projecting the capital expenditures associated with an enabling technology or method. Thus, the results show the upside or added value to a strategy (e.g. increased energy production), and not the potential downside (e.g. added capital cost of new hardware). The results of the analysis can therefore be used by industry stakeholders to take the cost savings presented in this report and add their revised technologies costs to arrive at a net decrease or increase in cost of energy resulting from a proposed IO&M strategy. This allows many technologies that target the same improvement area to be evaluated subsequent to this study. To clarify this concept, an example is presented below.

> Company X is interested in bringing an innovative vessel capable of operating at higher wind and wave conditions to market. If a strategy using an innovative vessel capable of operating in higher wind and wave conditions (similar to Company X's design) is shown to reduce costs by $100/kW with respect to the baseline, Company X can see that in order to be viable in the market, they must be able to deliver their innovative vessel at a rate no more than $100/kW greater than the vessel used in the baseline. If Company X can deliver their innovative vessel at $25/kW more than the baseline, they will have demonstrated that their new vessel technology is capable of saving $75/kW with respect to the baseline.

1.3 Scope of Work

The work in this study, titled "Analysis of Installation, Operation, and Maintenance Strategies to Reduce LCOE", identifies the principal IO&M cost drivers while quantifying their impacts on the cost of energy. The work also identifies a preferred IO&M strategy for a hypothetical U.S. offshore wind project through a case study. Project objectives focus on understanding near-term U.S. offshore wind installation and long-term operation and maintenance (O&M) costs.

As primary awardee for this project, NREL led all project management activities in addition to installation and LCOE analysis. Using data received through a separate contract with GL Garrad Hassan, a due diligence consultancy with direct experience in the area of offshore wind installations, NREL recently developed an offshore wind turbine installation cost model that is incorporated within the offshore balance of station (BOS) model. Using this new installation model, NREL conducted an analysis to identify primary installation cost drivers; the results quantify the potential impact on reducing the cost of energy for U.S. offshore wind projects.

NREL contracted with the Energy Research Centre of the Netherlands (ECN) to use its commercially available O&M Tool (Obdam, Braam, & Rademakers, 2011) to model U.S. site conditions. The ECN O&M Tool v.4 was modified to represent U.S.-specific vessel capabilities, costs, and metocean data. ECN conducted an analysis to identify primary O&M cost drivers using the newly adapted O&M Tool; the results quantify the potential impact on reducing the cost of energy for U.S. offshore wind projects.

The Team developed a hypothetical U.S. offshore wind plant case study to analyze the most practical means to reduce the cost of offshore wind energy while ensuring safety through advanced IO&M techniques. The case study used real-world wind and wave condition data, but parameters such as project size and distance from shore were chosen to represent a typical full scale wind plant. A suite of alternative IO&M techniques was identified and applied to the baseline hypothetical offshore wind project to quantify the impact on system LCOE. The Team developed a preferred strategy for the hypothetical U.S. offshore wind project based on this sensitivity analysis and international experience.

1.4 LCOE

In the past, the Wind Partnerships for Advanced Component Technology (WindPACT) studies, conducted by DOE and led by NREL, used LCOE as a comparative metric. This method provided valuable insight to evaluate innovative concepts for reducing the cost of energy for land-based wind projects (Malcolm & Hansen, 2006) (Griffin, 2001) (Shafer, et al., 2001) (Smith, 2001). Accordingly, LCOE will be the primary metric used to compare various IO&M strategies in this study. The LCOE analysis approach is an all-inclusive, cradle-to-grave analysis of costs and energy production related to a power production facility. LCOE analysis permits the evaluation of the life-cycle costs of an offshore wind project, including capital investment costs (including installation), O&M costs, finance costs, and estimated energy production.

For the purposes of this study, a number of assumptions had to be made with regard to the way LCOE is calculated (Short, Daniel, & Holt, 1995). We use the following equation and assumptions to calculate LCOE in this study:

$$LCOE = \left(\frac{ICC * FCR}{AEP}\right) + O\&M \tag{1.4-1}$$

Where:

$$ICC = OCC + (OCC * CF) \tag{1.4-2}$$

$$= Installed\ Capital\ Cost$$

$$OCC = TCC + BOS + Soft\ Costs \tag{1.4-3}$$

$$= Overnight\ Capital\ Cost$$

$$FCR = Fixed\ Charge\ Rate\ (Set\ to\ 11.8\%\ for\ this\ study^{3})$$

$$O\&M = Operation\ and\ Maintenance^{4}$$

$$AEP = Annual\ Energy\ Production$$

$$TCC = Turbine\ Capital\ Cost\ \left(Set\ to\ \frac{\$1800}{kW}\ for\ this\ study\right)$$

$$BOS = Balance\ of\ Station\ Costs$$

$$Soft\ Costs = Insurance + Contingency + Decommissioning \tag{1.4-4}$$

$$Insurance = (TCC + BOS) * 0.02 \tag{1.4-5}$$

$$Contingency = (TCC + BOS) * 0.1 \tag{1.4-6}$$

$$CF = Construction\ Financing\ (Set\ to\ 3\%\ for\ this\ study^{5})$$

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[3] (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012)

[4] O&M may be tax deductible to an extent. For the purposes of this study it is assumed that O&M has no tax deduction. If a tax deduction is applied to O&M, the impact on LCOE of any innovations in O&M would be less substantial. Sources suggest a 60% tax deduction may be appropriate (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012)

Financial parameters needed for the LCOE analysis have been selected from NREL's 2010 cost of energy review (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012) in an effort to represent expected U.S. offshore wind financial parameters as closely as possible. Because the turbine capital cost does not influence the relative results or conclusions of this analysis, a rounded value of $1,800/kW was used, based on values obtained from the 2010 Cost of Energy Review (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012). The BOS costs were estimated using NREL's offshore BOS model, which is described in more detail in Appendix B. The O&M and AEP values for the LCOE analysis were calculated using the ECN offshore O&M Tool, which is described in more detail later in the report.

[5] (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012)

2 Wind Plant Characteristics

2.1 Wind Plant Parameters

A hypothetical 500-MW wind plant consisting of 100 turbines of 5-MW rated capacity each, sitting atop monopile foundations, was established for all analyses in this study. The wind plant is assumed to be located in the Atlantic Ocean approximately 46 km (~25 nmi) off the coast of the U.S. state of Virginia, (see Figure 2.) The nearest port that is accessible for large vessels is The Port of Virginia at an approximate distance of 86 km (~46 nmi) from the wind plant (The Port of Virginia). The water depth at the location of the wind plant is approximately 30 m. The wind plant is assumed to be connected to the grid via an onshore substation, which is subsequently connected to a hypothetical offshore substation via two three-phase 220-kV subsea cables. Array cabling is arranged in a radial layout using three-phase 33-kV subsea cables.

For all wind and wave parameters, 120 months of Wavewatch III hindcast data files covering the period from January 1, 2000 through December 31, 2009 for the WIS grid point 63198 were used. The raw data is not freely available; however, more information on how the data were processed and used, as well as representative statistics can be seen in Appendix A.

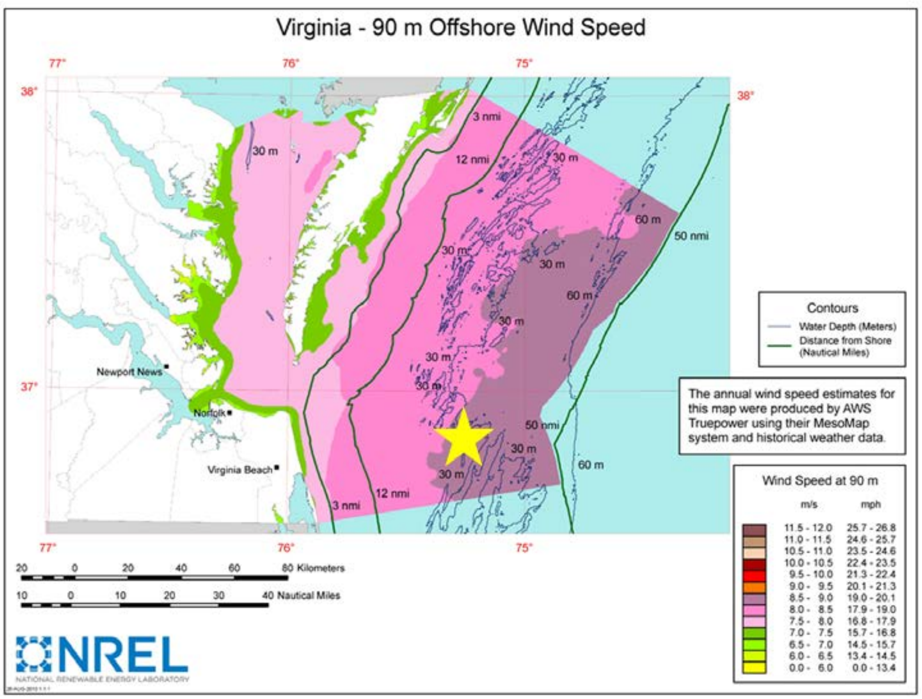

Figure 2. Assumed wind plant location

2.2 Wind Turbine Parameters

The 5-MW wind turbine used for reference in this study is the "NREL offshore 5-MW baseline wind turbine." This theoretical turbine is representative of typical utility-scale, multi-megawatt turbine. The turbine is controlled via a variable-speed, collective-pitch control system connected through a high-speed drive train, using a multiple-stage gearbox design (Jonkman, Butterfield, Musial, & Scott, 2009). Main turbine specifications are given in Table 6, and a plot of the power curve is given in Figure 3.

Table 6. Turbine specifications for NREL offshore 5-MW baseline reference wind turbine

Parameter	Value
Rotor diameter	126 m
Hub height	90 m
Rated power	5 MW
Power regulation	Variable speed, collective pitch control system
Nacelle Crane Capacity	2000 kg

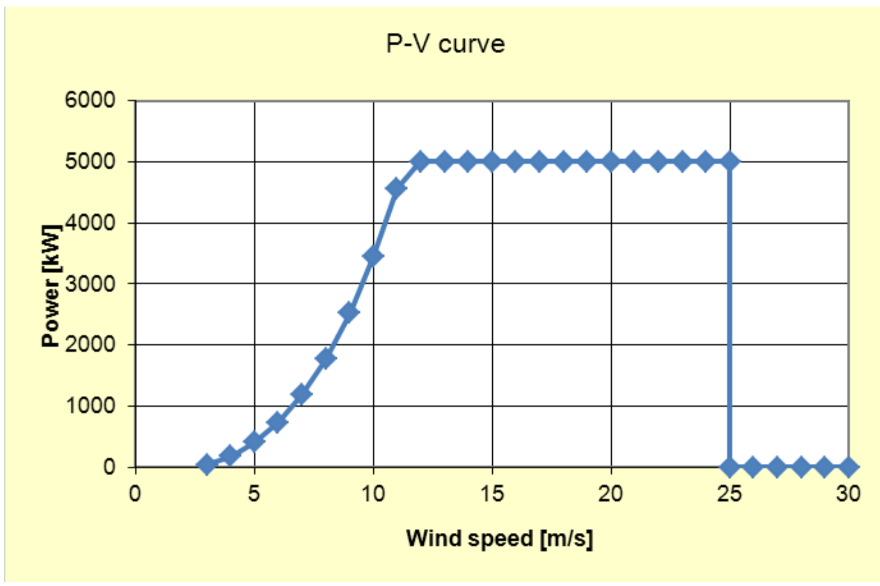

Figure 3. Power curve of the NREL offshore 5-MW reference wind turbine

The turbine is assumed to be equipped with an internal crane that is able to hoist small components like pitch motors and yaw drives (weight < 2000 kg). These components can be placed on a platform at the bottom of the tower during the replacement activities; hoisting can be done outside the tower using a crane located at the nacelle. For hoisting large components (generator, blades, nacelle, etc.) a large external crane is required, such as a crane on a jack-up vessel.

3 Baseline IO&M Strategy

3.1 Installation

For analyzing the baseline installation cost, NREL expanded the capability of its offshore BOS model. The model is capable of calculating budgetary level estimates for engineering, permitting, ports/staging, foundations, electrical infrastructure, vessels, and decommissioning. All noninstallation activities were calculated for the baseline using this model and were set constant for the analysis of the advanced installation strategies. A more detailed overview of the offshore BOS model and the data sources used therein can be seen in Appendix B.

3.1.1 Assumptions for baseline installation strategy

To calculate the baseline installation costs we had to account for several aspects of the associated port and staging costs as well as vessel costs.

We made the following port and staging, vessel, and installation assumptions:

- All installation activities are staged out of the nearby harbor facility at The Port of Virginia, located 86 km from the wind plant.
- The staging port is used to store 10 turbines at a time in preparation for installation.
- Turbine components are delivered to the staging facility as soon as the original turbines leave for installation (i.e., 10 turbines remain at port at any given time during the installation period).
- A dynamically positioned (DP2) heavy-lift cargo vessel is used to ferry the components from the foundation and turbine manufacturers to the staging port.
- A set of offshore barges and seagoing tugs transports the foundations and components from the staging port to the wind plant.
- A jack-up vessel is used to install the wind turbines.
- The baseline turbine installation requires seven offshore lifts:
    1. First half of the tower
    2. Second half of the tower
    3. Nacelle
    4. Hub
    5. Blade 1
    6. Blade 2
    7. Blade 3.
- Decommissioning of the wind plant is carried out in reverse order of installation, and at a faster pace with lower day rates for vessels. More detail on the decommissioning assumptions can be seen in Appendix B.

- Foundations and offshore substation are lifted and set in place using a heavy-lift vessel.
- Electrical cabling is installed with a cable-laying vessel with the assistance of a remotely operated vehicle (ROV).
- A horizontal drilling rig, along with a dive support team, is used for the landfall operations of the export cable.
- Supporting ocean-going tugs and crew vessels are used throughout the installation process.

In practice, increased installation efficiency may be expected as an increasing number of offshore wind turbines are installed, leading to cost reductions. However, relevant installation cost reduction data were not available for this analysis, so we held all installation costs constant for the baseline installation strategy (e.g., the installation costs for the first few turbines of the 100-turbine plant are equal to the costs of installing the last few turbines of the plant).

3.1.2 Baseline Installation Costs

The baseline installation strategy resulted in a total installation cost of $633 million dollars, which includes the costs of ports and staging and vessels. Vessel costs accounted for the majority of the total installation costs.

Of the total vessel costs during installation, the largest cost is that of the cable-laying vessel, but is followed closely by the heavy-lift vessel, and the jack-up vessel. These results suggest that improvement in installation-related activities can provide a significant reduction in installation costs. Possible solutions to reducing these vessel costs could include reducing the time needed for the vessel activities by improving processes, or reduced vessel costs through vessel ownership. Similar savings could be achieved during the decommissioning phase if the strategies were carried over.

Additional savings may be realized by eliminating the use of a staging port. Though the staging port is not an overwhelming cost item, implementing just-in-time delivery of components to the wind plant from the manufacturing facility may prove valuable. A summary of the baseline BOS costs is presented in Table 7.

Table 7. Baseline BOS cost items

Baseline BOS Cost Item	($/kW)	($/kWh)
Development	118	*0.0043*
Ports and Staging	26	*0.0009*
Support Structure	800	*0.0289*
Electrical Infrastructure	498	*0.0180*
Installation Vessels	1240	*0.0448*
Total	**2682**	**0.0969**

3.2 Operation & Maintenance

The ECN O&M Tool Version 4 was developed to estimate the long-term annual average costs and downtime of an offshore wind farm (ECN Wind Industrial Support, 2012). The O&M tool is most appropriate when used in the planning phase of a wind farm. The Tool was used to estimate the costs of our baseline O&M strategy.

The tool uses long-term average data as input (failure rates, wind and wave statistics, costs of vessels and spare parts, lead time of vessels and spare parts, etc.) and generates long-term average values as output (costs, downtime, and required resources). Evaluating a baseline scenario with the ECN O&M tool can reveal important O&M costs drivers, which can then be further analyzed via alternative scenarios to determine a preferred O&M strategy.

The tool is straightforward because it is programmed in MS-Excel. Each change in the input parameters immediately results in a change of the output parameters. The tool includes automatically generated tables, pie charts, and bar charts to identify the drivers for costs and downtime and to assist in defining an improved strategy. The model requires an extensive list of input parameters and a detailed description of the proposed O&M strategy. These requirements force the user to consider all aspects of O&M in detail.

In 2007, the tool received a validation statement from Germanischer Lloyd, which makes it the only software validated worldwide for analyzing offshore wind O&M.

To model O&M costs, six wind turbine maintenance categories (MCs) and four BOS MCs were used, in which each MC is split up into one or more fault type classes (FTC). The material costs, crew size, repair time and logistic time are all based on experience from ECN with O&M modeling. The FTCs were developed largely based on Obdam & van der Zee (Obdam & van der Zee, 2011). The FTCs are developed based on an analysis of the contribution to overall downtime and engineering judgment to classify small, medium, and large repair actions. These analyses were performed in the past by ECN together with a turbine manufacturer. The costs for spare parts are quantified using a breakdown that shows the contribution of different component costs to the total investment costs of a modern geared wind turbine. More detail on MCs and FTCs can be seen in Appendix C.

3.2.1 Assumptions for baseline O&M strategy

Generally, the costs for maintaining an offshore wind plant will be determined by both corrective and preventive maintenance. We used the ECN O&M tool to estimate the long-term yearly average O&M costs (including both corrective and preventive maintenance costs and condition-based costs, when applicable) for the wind plant, as well as turbine availability during the same time period. To develop the baseline scenario and determine the values of the inputs for the ECN O&M Tool, we made several assumptions that are spelled out in the following list.

- Component replacements:
    - The failure rate of components is constant over time.
    - Large components are not kept in stock at the harbor.

    - Small parts (up to 2000 kg) are kept in stock at warehouse facilities located at the harbor.
    - Small parts are picked up from the vessel with a crane on the platform of the transition piece of the turbines; they are then lifted into the nacelle using the internal nacelle crane.
- Vessel types and limitations:
    - Workboats:
        - Used to transport small components (up to 2000 kg) from the harbor to the turbines.
        - Provide access to the offshore substation for small repairs.
        - Provide technicians access to the turbine for the replacement of larger components.
        - Wave height restrictions for the workboats for the baseline scenario were established with the current U.S. offshore oil and gas O&M vessel fleet in mind. Based on industry communications, these vessels operate in significant wave heights ranging from 0.5 m to 1.3 m (Douglas-Westwood, 2012) (Frongillo, 2012). The average of this range, 0.9 m, is used for the baseline. Though typical offshore wind workboats in Europe have significant wave height restrictions around 1.5 m, those types of vessels are not currently operating in the United States and therefore were not considered for the baseline scenario.
    - Cable-laying vessel:
        - Required to repair power cables inside the wind plant
    - Diving support ship (and crew of divers):
        - Used for preventive maintenance of cables and foundations
    - Jack-up vessel:
        - Required for the replacement of larger components (weights in excess of 2000 kg)
        - Used to transport spare parts to the wind plant.
- Personnel:
    - Personnel work only during daylight periods—14 hours (h) in summer, 12 h in spring and autumn, and 10 h in winter—except for repairs that require the use of a jack-up vessel, when two shifts of technicians will work 24 h per day.
    - Technicians are paid $125/h per person (Obdam & van der Zee, 2011).
    - Two teams of technicians working in 12-h shifts carry out replacements of large components.

- Distance between harbor and wind plant:
  - Corrective and preventive maintenance will be performed from nearby harbor facilities located at The Port of Virginia, 86 km from the wind plant.
  - Average travel time to a turbine is 2.6 h, includes transfer of personnel to turbine.

Detailed O&M assumptions, including failure frequencies, repair costs, repair logistics, and general wind plant data, are presented in Appendix C.

3.2.2 Baseline O&M Costs

The baseline O&M scenario yields an availability of 84.5% and O&M costs of $0.0283/kWh, resulting in a total O&M effort (sum of O&M costs and revenue losses) of $86.9 million per year.[6] The majority of downtime is associated with corrective maintenance on the wind turbine and balance of plant structures.

For small and medium size failures, the largest portion of downtime is caused by the workboat vessel waiting for bad weather to clear. For large failures, a primary contributor to overall downtime is the long logistic (mobilization) time for the jack-up vessel. These results suggest that, for the baseline O&M scenario, downtime can best be reduced by employing a vessel(s) that has less strict weather limits in terms of allowable wave height (e.g., another type of vessel or a helicopter) and/or reducing the required weather window (WeWi) length (e.g., using mother vessel accommodations to reduce travel times). Additional downtime reduction could be achieved with long-term contracts or in-house operations to enable quicker access to jack-up vessels.

The majority of direct repair costs are related to corrective WT costs. For large replacements, the equipment costs dominate the total repair costs. Also, executing a long-term contract or in-house operations with a jack-up vessel may be beneficial if mobilization/demobilization costs could be lowered.

The baseline O&M results indicate that most downtime and costs are related to failures in the control and protection system generator, followed by the blade adjustment, drive train, control and protection system turbine, and generator systems. The use of condition monitoring systems might be feasible to apply condition-based maintenance, thereby reducing corrective maintenance costs and downtime.

Table 8 shows the breakdown of downtime and costs for the baseline O&M scenario. A breakdown is given for each of the four seasons, which are added in the Total column. The results in the Year column differ from the Total column because the values in the Year column were calculated for average annual weather windows, rather than seasonal weather windows. In this analysis we account for seasonal differences in weather windows by using all results from the Total column.

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[6] Total O&M effort numbers presented in this report represent the sum of revenue losses and accrued O&M costs on a yearly basis. The $/kWh O&M costs, however, do not include the direct cost of revenue losses. Rather, the impact from loss of revenue on a $/kWh basis is accounted for via the change in energy production.

Table 8. Costs and downtimes of the baseline caused by preventive and corrective maintenance

Summary of downtime and costs		***Availability [%]***	84.5%
Location	U.S. baseline IO&M case study	***Costs [$ct/kWh]***	2.83
Type of WT	NREL offshore 5-MW baseline	***Total effort [M $]***	86.9

ECN O&M Tool 4.4

Wind farm		100 turbines	Winter	Spring	Summer	Autumn	Total	Year
Downtime per year								
Corrective WT	Logistics	hr	3,333	3,308	4,378	3,308	14,327	13,232
	Waiting	hr	39,794	18,404	5,404	25,667	89,269	73,926
	Travel	hr	385	385	385	385	1,540	1,540
	Repair	hr	3,460	2,819	1,934	2,819	11,031	11,275
	TOTAL corrective WT	hr	46,971	24,916	12,101	32,179	116,167	99,973
Corrective BOP	Logistics	hr	1,999	1,999	1,999	1,999	7,995	7,995
	Waiting	hr	2,166	1,715	561	2,964	7,406	6,838
	Travel	hr	33	33	33	33	130	130
	Repair	hr	594	503	253	503	1,853	2,011
	TOTAL corrective BOP	hr	4,792	4,249	2,845	5,498	17,384	16,974
Preventive	**TOTAL preventive**	hr	0	924	1,452	264	2,640	2,640
	TOTAL	hr	**51,763**	**30,089**	**16,398**	**37,941**	**136,192**	**119,587**
Availability		%	76.4%	86.3%	92.5%	82.7%	84.5%	86.3%
Loss of production per year		MWh	145,677	70,631	25,840	83,854	326,003	269,765
Energy production per year		MWh	470,656	443,444	319,255	400,167	1,633,521	1,706,325
Revenue losses per year		kUSD	**18,210**	**8,829**	**3,230**	**10,482**	**40,750**	**33,721**
Costs of repair per year								
Material costs								
Corrective WT	**TOTAL corrective WT**	kUSD	4,171	4,171	4,171	4,171	16,684	16,684
Corrective BOP	**TOTAL corrective BOP**	kUSD	15	15	15	15	58	58
Preventive	**TOTAL preventive**	kUSD	0	551	866	157	1,574	1,574
	TOTAL	kUSD	**4,186**	**4,737**	**5,052**	**4,343**	**18,317**	**18,317**
Labour costs								
Corrective WT	**TOTAL corrective WT**	kUSD	1,164	1,102	997	1,102	4,366	4,410
Corrective BOP	**TOTAL corrective BOP**	kUSD	1	1	1	1	5	5
Preventive	**TOTAL preventive**	kUSD	0	778	1,103	222	2,103	2,224
	TOTAL		**1,166**	**1,882**	**2,100**	**1,326**	**6,474**	**6,639**
Costs equipment								
Corrective WT	MOB/DEMOB	kUSD	1,405	981	1,248	981	4,615	3,924
	Waiting	kUSD	1,871	1,305	787	1,416	5,379	5,209
	Repair	kUSD	2,192	1,959	2,326	1,955	8,432	7,826
	TOTAL corrective WT	kUSD	5,468	4,245	4,362	4,352	18,426	16,959
Corrective BOP	MOB/DEMOB	kUSD	150	150	150	150	598	598
	Waiting	kUSD	66	63	57	68	255	251
	Repair	kUSD	155	152	152	152	611	609
	TOTAL corrective BOP	kUSD	370	365	359	370	1,464	1,458
Preventive	**TOTAL preventive**		0	565	761	161	1,487	1,610
	TOTAL		**5,838**	**5,174**	**5,482**	**4,882**	**21,376**	**20,027**
Corrective WT		kUSD	**10,803**	**9,518**	**9,530**	**9,625**	**39,476**	**38,053**
Corrective BOP		kUSD	**386**	**380**	**374**	**386**	**1,527**	**1,522**
Preventive		kUSD	**0**	**1,894**	**2,730**	**541**	**5,164**	**5,408**
Fixed yearly costs		kUSD	**0**	**0**	**0**	**0**	**0**	**0**
Total costs of repair		**kUSD**	**11,189**	**11,793**	**12,634**	**10,552**	**46,168**	**44,983**
Total cost per kWh		**USD cent/kWh**	**2.38**	**2.66**	**3.96**	**2.64**	**2.83**	**2.64**
Total costs of repair per kW installed		**USD/kW**	**22**	**24**	**25**	**21**	**92**	**90**
Total cost per kW investment			**1.2%**	**1.3%**	**1.4%**	**1.2%**	**5.1%**	**5.0%**
Total effort								
Sum revenue losses & total costs of repair		**kUSD**	**29,399**	**20,622**	**15,864**	**21,033**	**86,918**	**78,704**

3.3 Baseline LCOE

As mentioned in the introduction, the primary metric used for comparison in this study is levelized cost of energy. Annual energy production estimates were calculated using the ECN O&M Tool (Obdam, Braam, & Rademakers, 2011) on a seasonal basis using the same wind data set used for the waiting and downtime analysis, detailed in Appendix A. The wind data is presented at an elevation of 10 m and is extrapolated to a hub height wind speed using a standard shear exponent of 0.1. This extrapolation of wind speeds may lead to uncertainty in the absolute energy capture of the wind plant; however, because of the comparative nature of the analysis, this extrapolation does not affect the relative impacts of the different IO&M strategies on LCOE.

Based on the baseline assumptions and analysis presented in sections 3.1 and 3.2, in conjunction with the LCOE equations from the introduction, we calculated the baseline LCOE (Table 9).

Table 9. Summary of baseline LCOE

	($/kW)	($/kWh)
Turbine Capital Cost	1800	0.0650
Development	*118*	*0.0043*
Port and Staging	*26*	*0.0009*
Support Structure	*800*	*0.0289*
Electrical Infrastructure	*498*	*0.0180*
Installation Vessels	*1240*	*0.0448*
Balance of Station	2682	0.0969
Insurance	*90*	*0.0033*
Decommissioning	*471*	*0.0170*
Contingency	*448*	*0.0162*
Soft Costs	1009	0.0364
Overnight Capital Cost (OCC)	5491	0.1983
Construction Financing	*165*	*0.0060*
Installed Capital Cost (ICC)	5656	0.2043
O&M ($/kW/yr)	784	0.0283
Net Annual Energy Production (AEP) (MWh/MW/yr)	3267	
Fixed Charge Rate (FCR)	11.8%	
Levelized Cost of Energy ($/kWh)	**0.233**	

Roughly 12% of the baseline LCOE is attributable to O&M and 20% to installation activities. With more than 30% of the LCOE attributable to IO&M activities, there is significant opportunity for cost reduction through IO&M improvement.

The baseline LCOE is in line with estimates for future offshore wind plants in the general vicinity of the baseline project, with the primary exception of AEP (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012). The considerably low availability and AEP in the baseline case is attributable almost exclusively to the work boat wave restriction of 0.9 m (Douglas-Westwood, 2012), which is below values based on European experience used in other analyses (Tegen, Hand, Maples, Lantz, Schwabe, & Smith, 2012). Additional reasons for possible differences in baseline LCOE could stem from vessel cost assumptions, which can vary substantially. The reader should note that this baseline LCOE is substantially dependent on the specific baseline assumptions presented above. In the event that any of the assumptions are altered, depending on the sensitivity of the assumption to LCOE and how much it is varied, the baseline LCOE may be substantially different. In some cases, like those mentioned above, changes in a single assumption can alter the baseline LCOE by ±50%.

4 Advanced IO&M Strategies

At the onset of the project, a panel of subject matter experts was gathered to brainstorm about advanced IO&M strategies. A list of approximately 30 potential IO&M strategies was established and subsequently down-selected. The down-selected strategies were chosen based on three criteria:

1. Potential impact to LCOE (the larger the reduction the better),
2. Ease of accurate representation in models (easier the better), and
3. Assumed time to market of the strategy (shorter the better).

The down-selected IO&M strategies included four installation strategies and six O&M strategies. Representatives from the following organizations provided input to the brainstorming session:

- Siemens
- General Electric
- Vattenfall
- Global Marine Energy
- Douglas-Westwood
- GL Garrad Hassan
- Romax Technology
- Knud E. Hansen USA
- U.S. Department of Energy
- American Wind Energy Association
- NREL
- ECN.

It should be noted again that some of the analyses are presented in a way in which capital expenditures associated with an enabling technology or strategy were not included in the analysis. This analysis procedure allows the reader to understand the limitations on increased costs associated with implementing a particular strategy or technology, thus allowing many technologies that target the same improvement opportunity area to be evaluated for their relative value subsequent to this study.

4.1 Installation

The proposed strategies to reduce LCOE via changes to installation activities are:

- Division of land-based vs. offshore turbine assembly
- Direct delivery of turbine and foundation components
- Project-owned, purpose-built installation vessel
- Modified electrical and foundation installation approaches.

In the following subsections, we discuss our analysis of each of the strategies in more detail, including the effect on installation time and costs and a qualitative analysis of possible limitations. A summary of the quantitative results from each of these strategies is presented in Figure 5.

4.1.1 Division of Land-based vs. Offshore Assembly

Wind turbines can be assembled in a variety of methods that combine assembly at port or at the wind plant. The adoption of a particular method will impact transportation, installation weather windows, and vessel requirements for the installation. There is inherent variability in the duration of any given installation activity; throughout this report, we present the average expected installation duration as well as a range (minimum and maximum duration). We used the average duration estimate in our analyses. The time, wind, and wave limits as shown in Table 10 were inputs for our analysis of the six wind turbine installation methods. The average installation duration is shortest for the *fully pre-assembled* strategy (8 h) and longest for the *individual components* strategy (34.5 h).The duration of installation is primarily a factor of the number of offshore lifts required for each installation method. Table 11 presents the total number of lifts and the sequence of the lifts for each of the installation strategies.

Table 10. Time, wind, and wave limits for the six wind turbine installation strategies investigated

	Min. duration [h]	Max. duration [h]	Avg. Duration [h]	Wind speed limit [m/s]	Hs* limit [m]
Individual components	30	39	34.5	8	2
Bunny ears with 2-part tower	21	28	24.5	8	2
Bunny ears with 1-part tower	15	20	17.5	8	2
Pre-assembled rotor with 2-part tower	24	30	27	8	2
Pre-assembled rotor with 1-part tower	18	22	20	8	2
Fully pre-assembled	8	8	8	8	0.75

*High seas

Table 11. Offshore lift operations for each installation strategy investigated

<table>
<tr><th>WT Install Method</th><th>Total Lifts</th><th>Lower Tower</th><th>Upper Tower</th><th>Nacelle</th><th>Hub</th><th>Blade 1</th><th>Blade 2</th><th>Blade 3</th></tr>
<tr><td>Individual components</td><td>7</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td></tr>
<tr><td>Bunny ears with 2-part tower</td><td>4</td><td>1</td><td>2</td><td colspan="4">3</td><td>4</td></tr>
<tr><td>Bunny ears with 1-part tower</td><td>3</td><td colspan="2">1</td><td colspan="4">2</td><td>3</td></tr>
<tr><td>Pre-assembled rotor with 2-part tower</td><td>4</td><td>1</td><td>2</td><td>3</td><td colspan="4">4</td></tr>
<tr><td>Pre-assembled rotor with 1-part tower</td><td>3</td><td colspan="2">1</td><td>2</td><td colspan="4">3</td></tr>
<tr><td>Fully pre- assembled</td><td>1</td><td colspan="7">1</td></tr>
</table>

Not all installation strategies will be appropriate for all projects. Among the many factors that will determine which installation methods can be used in a particular project, two important factors include the vessel specifications and possible restrictions on transportation methods. Within a class of vessels (e.g., heavy lift vessels or self-propelled jack-up vessels), the characteristics of each individual vessel (e.g., crane capacity, deck space, and weight limits) will determine which installation methods are possible and most suitable. Another influencing factor in determining what transportation option best matches the project goals is the possible restriction on transportation methods approved by the wind turbine manufacturer because of stress placed on different components during transportation.

In practice, the vessel selection process is heavily dependent on vessel availability and market conditions, as well as turbine and foundation designs. The model used in our analysis does not specifically address the impact of vessel selection on the installation strategy. Because of this generalization, the model does not account for the influence of factors such as the number of turbines that can fit on a given vessel per trip. Consequently, if one were to investigate these strategies for a specific project with prescribed vessel and component dimensions, the results may vary from those presented here.

It should be noted that the fully pre-assembled turbine is installed using a sheerleg crane barge, a type of heavy lift vessel. All other methods use a jack-up vessel that is assumed to have suitable crane capacity. Average day rates for the jack-up and shear-leg crane vessels are $155,000 per day and $675,000 per day, respectively (Douglas-Westwood, 2012).

Based on the analysis, the least-cost method available was the bunny ears strategy with 1-part tower, and the most expensive was the fully pre-assembled strategy. Except for the fully pre-assembled method, all other methods differed by a cost range of less than $300/kW, as seen in Figure 4.

The fully pre-assembled WT installation method has costs much higher than other methods for several reasons. Despite the single lift requiring the least offshore operations time, the method is affected significantly by weather limits. All other methods have a wind and wave limit of 8 m/s and 2 m, respectively, while the fully pre-assembled method has a wave height limit of 0.75 m. This has a large influence in the weather windows at the site and increases the overall average installation time to slightly less than that required for the individual components method, which had the lengthiest installation time. Additionally, the heavy lift sheerleg crane is substantially more expensive than the jack-up vessel used for the other installation strategies. The use of a more expensive vessel was more of a factor than the increased time caused by strict weather limits. Even if the sheerleg crane barge could be used with a wave limit of 2 m, the vessel cost still makes the fully pre-assembled method the most expensive option, despite the decrease in installation time because of the need for the least number of lifts.

The range of costs seen in Figure 4 is the result of the maximum and minimum anticipated installation durations shown in Table 10. The variation of WT installation duration could be a result of crew experience, improved installation techniques, design improvements, or ship modifications that affect the installation time.

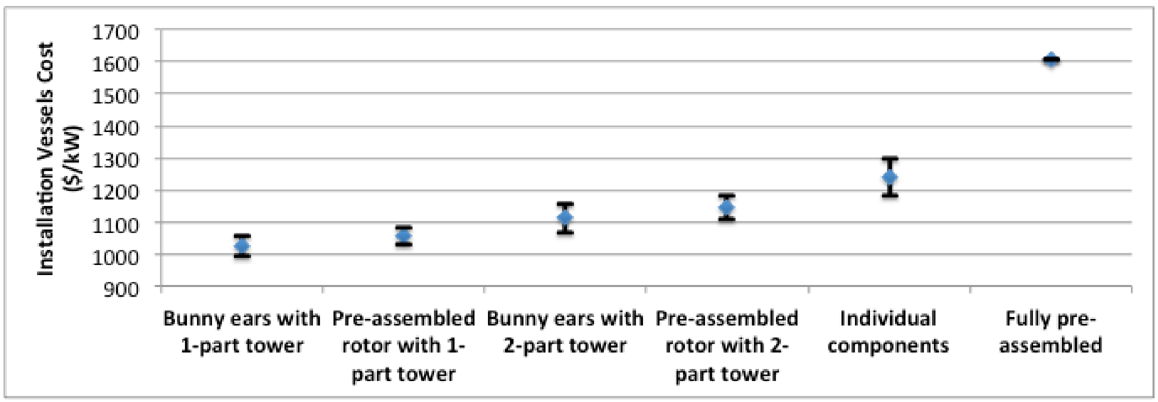

Figure 4. Impact of assembly strategy on installation vessel costs

4.1.2 Direct Delivery of Turbine and Foundation

Turbines and foundations may be delivered from the manufacturers and fabricators to a staging port and then transported to the project site, or delivered directly to the project site (bypassing a staging port). Though not the primary driver of overall project costs, port and staging expenses can total in the tens of millions of dollars. The need for a staging port is driven by several factors that can vary between projects, including size of project, WT installation method, and distance to component manufacturers.

We evaluated installation strategies that included a staging port as well as strategies that do not (i.e., direct delivery). We assumed there would always be a stock of components available for installation at the staging port and that delivery of components to the staging port would keep up with the installation rate. For the analysis of strategies that do not use a staging port, we assumed all components would be picked up for installation from the manufacturer's port, located 150 km from the project site.

In this analysis, the use of a staging port is the least-cost option by $213/kW, although project-specific conditions could cause the use of a staging port to be less cost-effective. For example, in the case of the bunny ears with 1-part tower strategy, the use of a staging port is not the least cost option if the project size is reduced from 500 MW to less than 100 MW. Other factors that can impact the economic effectiveness of a staging port are the distance of the component manufacturers to the proposed staging port, the need for separate delivery and installation vessels, speed of the vessels, and percentage of assembly at port versus at sea.

4.1.3 Purpose-Built Installation Vessel

The scarcity of suitable turbine installation vessels in the U.S. market could lead to some early projects building a purpose-built vessel, which could then be used on an ongoing basis for O&M or leased to other projects. For this strategy we assume that a jack-up vessel, the major installation vessel for the wind turbines, is purpose-built for the project. This vessel accounts for just over 10% of the vessel costs. For the sensitivity analysis, we assume the operating expenses during installation activities for the project-owned jack-up vessel are estimated at $77,500 per day, 50% of the baseline dayrate based on estimates from (Kaiser & Snyder, 2010).

Based on the reduced day rate of the project owned jack-up vessel, the analysis shows a potential savings of $41 million if the investment cost of the vessel is set to zero. With estimates of jack-up vessel capital cost around $120 million, the savings from installation alone would not justify the capital cost of a purpose-built vessel. If the savings from the installation phase of the project were to be combined with the potential savings during the operational phase of the project, it may be financially viable. This combined analysis is presented in detail in section 5.3.

Additional motivation for a developer building and operating its own installation vessel is the ability to customize the vessel specification to optimize its use. The impacts of customization are heavily dependent on specific turbine specifications, and therefore beyond the scope of this more generalized analysis. If an analysis was completed for a specific turbine, location, and baseline vessel, the results may indicate that savings from the installation period of vessel use would be sufficient enough to justify costs for a purpose-built vessel.

4.1.4 Electrical and Foundation

To investigate the sensitivity of total BOS cost to changes in electrical and foundation installations approaches we conducted a parametric study. We varied the electrical installation costs ($/km) by ±25% to demonstrate the impact of potential future innovative technologies. Separately, we varied the foundation installation time by ±3 h per foundation, from a low of 20 h to a high of 26 h, to represent average bounds in current foundation technology installation times (GL Garrad Hassan, 2012).

The foundation parametric study shows an influence of ±$50/kW on overall BOS cost, but like the electrical impact of ±$80/kW, it is not as impactful as the other installation strategies evaluated.

4.1.5 Summary

Figure 5 summarizes the results of each of the installation strategies investigated with respect to the baseline installed BOS cost (BOS + insurance + contingency + construction financing). The different land-based versus offshore assembly strategies have the potential to incur the biggest impact on BOS cost, reducing it by almost $300/kW compared to the baseline, or increasing it by approximately $650/kW. The strategy of arranging direct delivery of components to the project site (bypassing a staging port) increases the BOS cost compared to the baseline, as does the use of a purpose-built installation vessel. Changes to the foundation installation duration would have the smallest impact on BOS costs compared to the baseline, and innovations affecting the electrical installation could have a slightly larger impact (either increasing or decreasing total BOS costs, depending on whether the innovation increased or decreased the electrical costs).

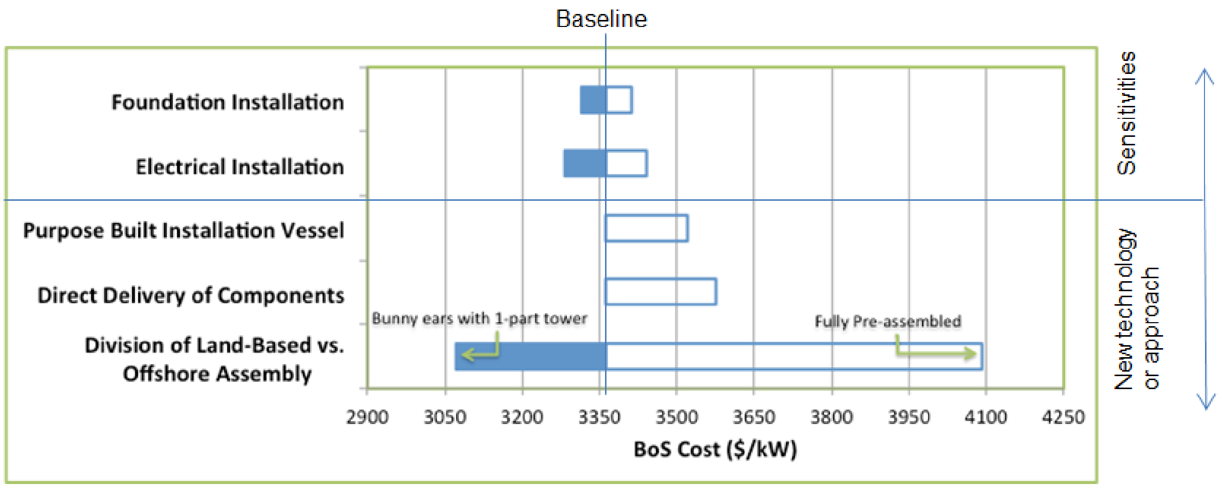

Figure 5. Summary of the impact of the installation strategies studied

4.2 Operation & Maintenance

The proposed O&M strategies are:

- Mother vessel accommodation
- Helicopter access
- O&M vessel contracts
- Improved crew transfer system
- Spare part storage
- Advanced CBM.

Our analysis investigated how each of the proposed strategies affects downtime and O&M costs relative to the baseline O&M strategy. In the following subsections we present our findings, including a qualitative analysis of possible limitations for each of the alternative O&M strategies as well as a summary of the qualitative results (Table 16).

4.2.1 Mother Vessel Accommodations

Mother vessel accommodation has the benefit of significantly reducing the time to access the wind plant for minor repairs or inspection, with respect to operating out of port. Additionally, because of the reduced travel times, the fair weather windows are smaller, thus allowing for more weather window opportunities that also reduce wind plant downtime. There are also disadvantages; both costs of vessels and worker wages are higher with the use of offshore accommodations.

For the baseline scenario, we assume that maintenance is organized from the Port of Virginia at an approximate distance of 86 km from the wind plant. This results in a one-way travel time of 2.6 h. In this subsection we discuss whether organizing the maintenance from an offshore base (e.g., a mother vessel) is beneficial for this location.

The mother vessel accommodations scenario differs from the baseline scenario in two ways. First, corrective and preventive maintenance will be performed from a mother vessel located inside or close to the wind plant. From this mother vessel, workboats can be launched with an average travel time of 0.5 h, including the transfer of personnel to the turbine. Second, small parts (up to 2000 kg) will be kept in stock at the mother vessel instead of the harbor.

Very little information is available on the costs for such a mother vessel in the United States. As a result, we chose not to include an estimated mother vessel cost to avoid false or misleading results. Instead, we consider only the benefits associated with this strategy. When more information on the investment and operational costs for a mother vessel become available the results of this analysis can be used to assess whether the use of a mother vessel would be an economically prudent solution.

Organizing the maintenance from a mother vessel results in a significantly improved availability, compared to the baseline scenario, in which workboats are launched from shore. The total downtime for corrective maintenance is reduced by almost a factor of two; reduced downtime caused by waiting for good weather is the largest contributor to this reduction. This can be explained as follows:

- Because of the shorter travel time each day, 4.2 h of additional working time on the turbines is available compared to the baseline; therefore repairs can be completed in fewer days.
- Waiting time is a function of the length of the total mission. The shorter repair time combined with the shorter travel time results in a significantly reduced total mission time, which causes an even more significant reduction of the waiting time.

The costs of repairs are also reduced, albeit by a smaller percent than for downtime. The main causes for the cost reduction are the lower costs for equipment during waiting and repair and reduced labor costs because everything with a day or hourly rate is utilized for less time.

Again, it should be emphasized that this analysis did not account for costs of acquiring or operating the mother vessel. If more information about the costs of such vessels for the U.S. market becomes available, it can be assessed whether the calculated savings ($25 million per year compared to the baseline) are sufficient to justify the additional cost of:

- Investment in a mother vessel
- Operation of a mother vessel

- More expensive offshore technicians because they must live and work offshore for a prolonged period of time.

4.2.2 Helicopter Access

The advantage of using helicopters is that access to the wind plant is not limited by wave height, as is the case for workboats. Furthermore, travel times can be reduced. There are also disadvantages; no spare parts can be transported via helicopter, and both costs and safety risks are higher with the use of a helicopter.

In this scenario helicopters instead of workboats are used for small repairs and inspections (for which no spare parts are required). For all repairs for which spare parts are required, workboats are used to transport those parts from the harbor to the wind plant (the same as in the baseline scenario). Workboats are used to transfer technicians for preventive maintenance on the wind turbines and corrective maintenance on the BOS in both the baseline and the helicopter access scenario.

New model inputs were needed to perform this analysis. The helicopter's application for repair and its specifications are detailed in Table 12 and Table 13.

Table 12. Model input for the helicopter

Nr of equipment	Description of equipment	Weather window (normal day)	Hs	Vw	0	0	Availability (nr. of equipment)	T logistic equip.				T travel (+access) one way				
			(For information only)				nr	hr				hr				Freq. 0: day 1: mission
1	Workboat	3	0.90	12.0	0.00	0.0		0				2.6				0
2	Jack-up barge (100 MT)	1	2.50	10.0	0.00	0.0		720								1
3	Cable layer	5	1.00	25.0	0.00	0.0		720								1
4	Diving support vessel	6	2.00	25.0	0.00	0.0		360								1
5	Turbine crane	7	0.90	10.0	0.00	0.0										
6	Blade inspection	8	0.90	8.0	0.00	0.0										
7	Helicopter	9	5.00	12.0	0.00	0.0		0				1.0				0
8			0.00	0.0	0.00	0.0										
9			0.00	0.0	0.00	0.0										
10			0.00	0.0	0.00	0.0										
11			0.00	0.0	0.00	0.0										
12			0.00	0.0	0.00	0.0										
13			0.00	0.0	0.00	0.0										

Nr of equipment	Description of equipment	Fixed costs per available equipment [USD/year]				Cost equipment for MOB/DEMOB [USD/mission]				Variable cost equipment (waiting and repair) [USD/unit]						Additional costs equipment during traveling [USD/trip]			
		USD/year				USD/ mission				USD/ unit				unit 0: hr 1: day	Weighing factor Costs T_wait	USD/trip			
1	Workboat									2,000				1	0.75	500			
2	Jack-up barge (100 MT)					440,000				155,000				1	0.75	310,000			
3	Cable layer					560,000				190,000				1	0.75	190,000			
4	Diving support vessel					190,000				95,000				1	0.75	95,000			
5	Turbine crane																		
6	Blade inspection																		
7	Helicopter															8,000			
8																			
9																			
10																			
11																			
12																			
13																			

Table 13. Specifications for the helicopter

Helicopter – 3 persons		
Specification	**Value**	**Remarks**
H_s max at transfer	Not relevant	Modeled as 5.0 m
V max at transfer	12 m/s	This limit refers to the maximum allowed wind speed for personnel working in the nacelle (Obdam & van der Zee, 2011).
Travel time to turbine (or speed)	1.0 h	*Estimate*
Maximum crew size	3	*Assumption, equal to 1 crew*
Mobilization time	0 h	*Assumption, depends on contract*
Maximum weight of load	-	Only technicians and consumables
Hourly rate	$2,000/h	*Estimate* Modeled as fuel costs
Mob + demob costs	0	No MOB/DEMOB costs applicable
Fuel costs	$8,000 per mission	Per mission: 1.0 (time) * 4 (trips) * 2 (rate) = $8k

H_s = High seas V = wind velocity

Using a helicopter for small repairs and inspections will improve the wind plant availability by 2.6%, bringing it up to 87.1%. The reduced downtime caused by waiting is the main reason for the improved availability. The downtime associated with travel is also reduced compared to the baseline scenario.

The total costs of repair are slightly higher than the baseline because the helicopter is more expensive than the workboat. Additional revenues (from higher wind plant availability) offset the higher cost of repair; we estimate annual savings of $4 million compared to the baseline scenario. It should be noted that the analysis did not account for the following (which would affect the total costs of the helicopter access scenario).

- Helicopter ownership and logistics choices:
    - The helicopter could be owned by the operator of the wind plant (and located in the harbor), which would require an additional capital investment.
    - The wind plant operator could lease the helicopter (with the condition of immediate access when called upon) requiring an annual lease payment.
- An additional investment is necessary to equip all turbines with facilities for helicopter access.

4.2.3 Vessel Contracts

Vessel contracts aim to reduce downtime by establishing a paid agreement between the project operator and the vessel operator that guarantee vessel availability under short notice. Vessel contracts for large offshore crane vessels may be needed because of the long lead time associated with these high-demand, low-availability vessels. These agreements will come with a high price; however, in some cases the reduced down time can lead to substantial cost savings through increased wind plant availability.

The costs for jack-up vessels have a substantial impact on the total O&M costs, especially when rented on the spot-market because of a long logistics time (lead time) and high mobilization and demobilization costs (MOB/DEMOB).

To assess the validity of using a vessel contract, we quantify both the impact of logistics time and MOB/DEMOB costs of the jack-up vessel on the project's LCOE (according to equation 1.4-1). The output of this calculation can be used to assess how much money can be spent on a fixed contract, which results in a shorter logistics time and lower costs per mission.

The sensitivity of the LCOE to the MOB/DEMOB costs and logistics time is shown in Figure 6. As expected, the lower the MOB/DEMOB costs, the lower the LCOE. A lower logistics time, however, does not necessarily yield cost savings; the LCOE is actually higher when the logistics time is less than the baseline scenario (720 h in the baseline,). This difference can be explained by the fact that the model accounts for the clustering of large repair actions. The model assumes that all failures that occur during the logistics/mobilization period can be clustered, which leads to a reduction in total MOB/DEMOB costs, travel costs, and logistics downtime. For a shorter logistics time, on average, fewer repairs will be clustered. An average of two jack-up repairs were clustered in the baseline scenario (which assumes a logistics time of 720 h), whereas no clustering occurred for shorter logistics times. Figure 6 indicates that this "turning point" lies between a logistics time of 360 and 720 h, based on the assumed failure frequencies used.

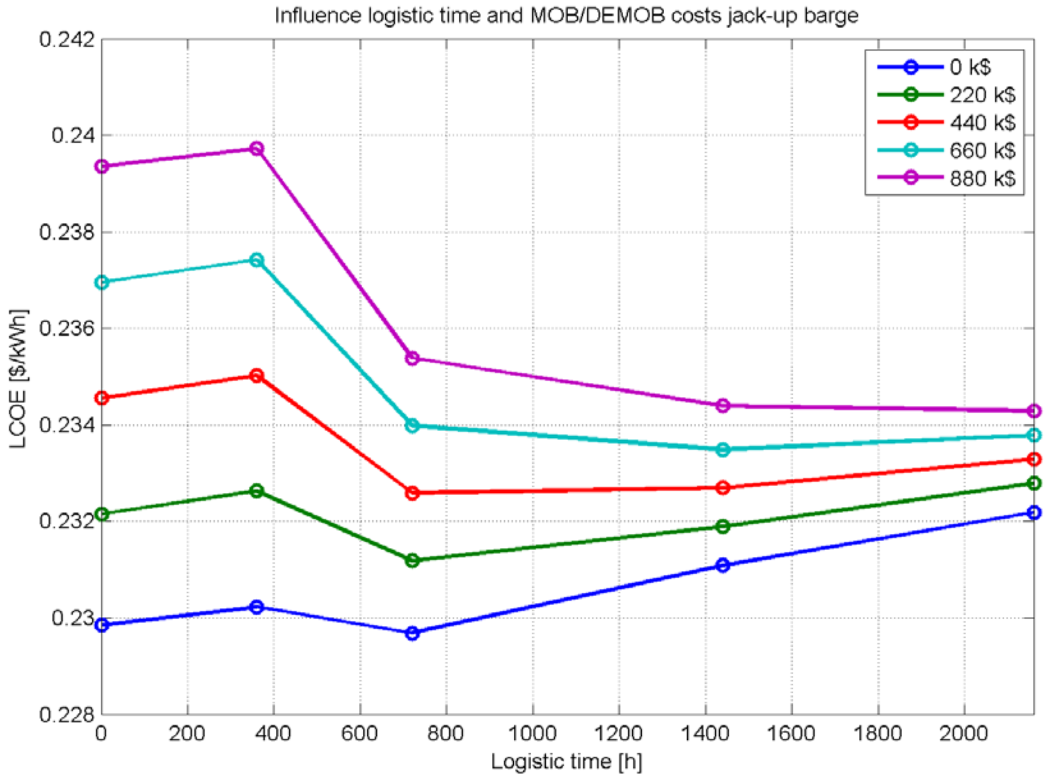

Figure 6. LCOE as a function of logistic time and MOB/DEMOB costs of a jack-up vessel

Negotiating a shorter logistics time will not necessarily yield cost savings, because doing so could reduce the number of repairs that can be clustered and therefore the full MOB/DEMOB and travel costs will have to be paid for each replacement. According to this analysis, a fixed contract can only be favorable if the costs per event (MOB/DEMOB and possibly travel costs) can be lowered significantly.

4.2.4 Improved Crew Transfer System

The workboats used for crew transfer in the baseline scenario were assumed to only allow access to the turbines in conditions with significant wave heights of up to 0.9 m (Douglas-Westwood, 2012) (Frongillo, 2012). This limitation results in very low wind plant availability of 84.5%. In the following subsection, we discuss the effect of the weather limits of the crew transfer system on the downtime and O&M costs.

Consistent with the analysis methodology used throughout this report, we did not address specific boat technology; instead, our analysis focused on the effect of the weather limits of the workboats. We varied the maximum allowed significant wave height for this equipment from 0.7 m to 3.0 m and evaluated wind speed limits of 12 m/s and 16 m/s.

For the baseline scenario, the wave height limit for the turbine cranes and blade inspection were set equal to the wave height limit of the workboat. Similarly, the wave height limits for the turbine cranes and blade inspection for the improved crew transfer system scenarios were also set equal to the various workboat wave height limits.

As shown in Figure 7, the maximum allowed wave height for the workboats has a significant influence on availability, costs, and the number of technicians needed. The availability for the baseline scenario (where $H_{s,\,max}$ = 0.9 m was used) was low (84.5%), but drops to completely unacceptable levels if the wave height limit is reduced even further (0.7 m). As the wave height limit increases, availability increases asymptotically towards 95%, but increasing the wave height limit above 1.7 m yields negligible increases in availability. Figure 7 also shows that the wind speed limit for working in the nacelle has little or no influence on any of the parameters evaluated (availability, O&M costs, total effort, or number of technicians employed).

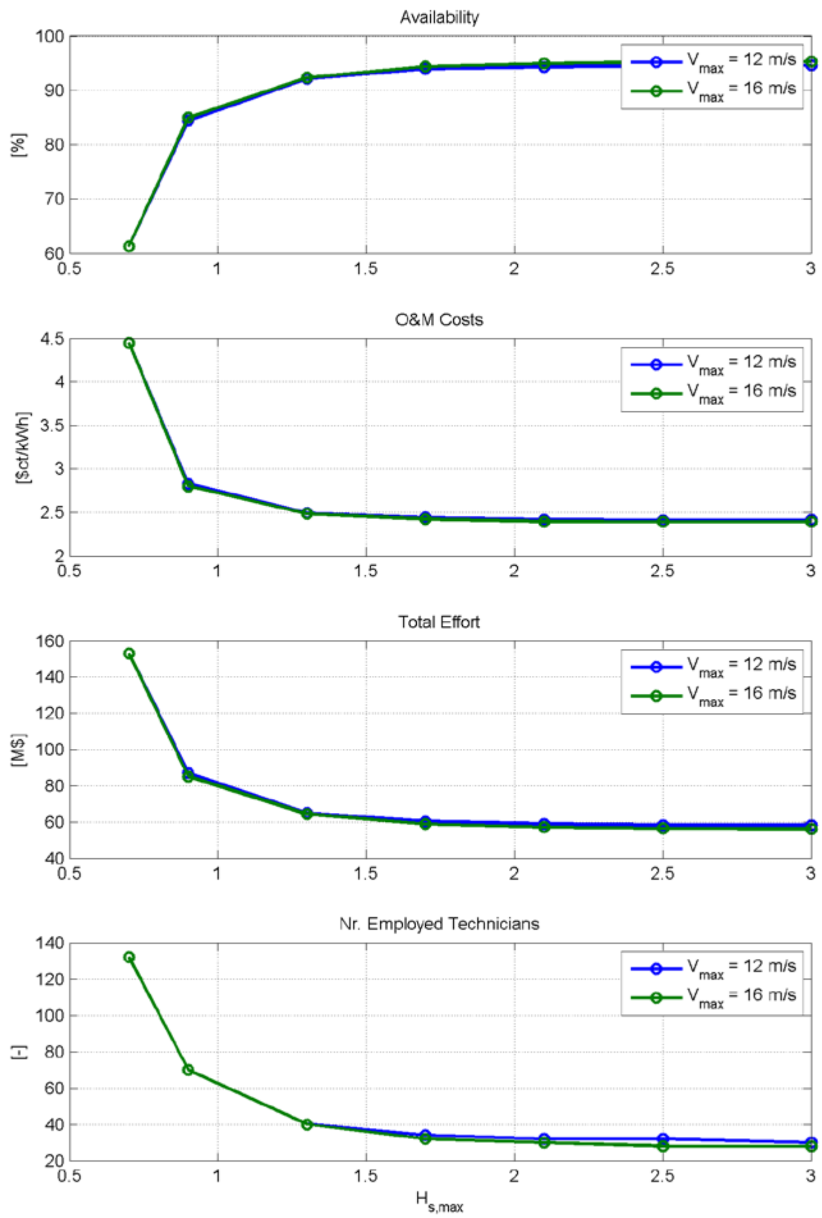

Figure 7. Model output as a function of the maximum allowed significant wave height of the workboats

When interpreting these results it should be emphasized that only the weather limits of the workboats (and associated procedures) were changed. Naturally, different crew transfer systems will have different costs and, possibly, travel speeds, which will also impact the availability and O&M costs. If in the future more detailed information on alternative crew transfer systems for the U.S. market becomes available, the analyses discussed in this section could be used to identify the most optimal solution. However, from these results it can already be concluded that it is probably not reasonable to invest in crew transfer systems that can operate up to very high (> 2.0 m) wave heights in the U.S. mid-Atlantic area.

The results of this analysis are entirely dependent on wind and wave conditions of the mid-Atlantic. As seen in Figure 8, the significant wave height distribution between the mid-Atlantic and the North Sea are quite different. With a vessel wave restriction of 1.5 m in the mid-Atlantic, the wind plant would be accessible nearly 90% of the time, whereas in the North Sea, the wind plant would only be accessible roughly 60% of the time. To achieve more than 80% accessibility in the North Sea, work boats would need to have wave restrictions well above 2 m, and limits closer to 3 m to reach availability levels close to 90%. This substantial difference in wave conditions demonstrates how the conclusions of this study could change substantially if different wind and wave conditions were used.

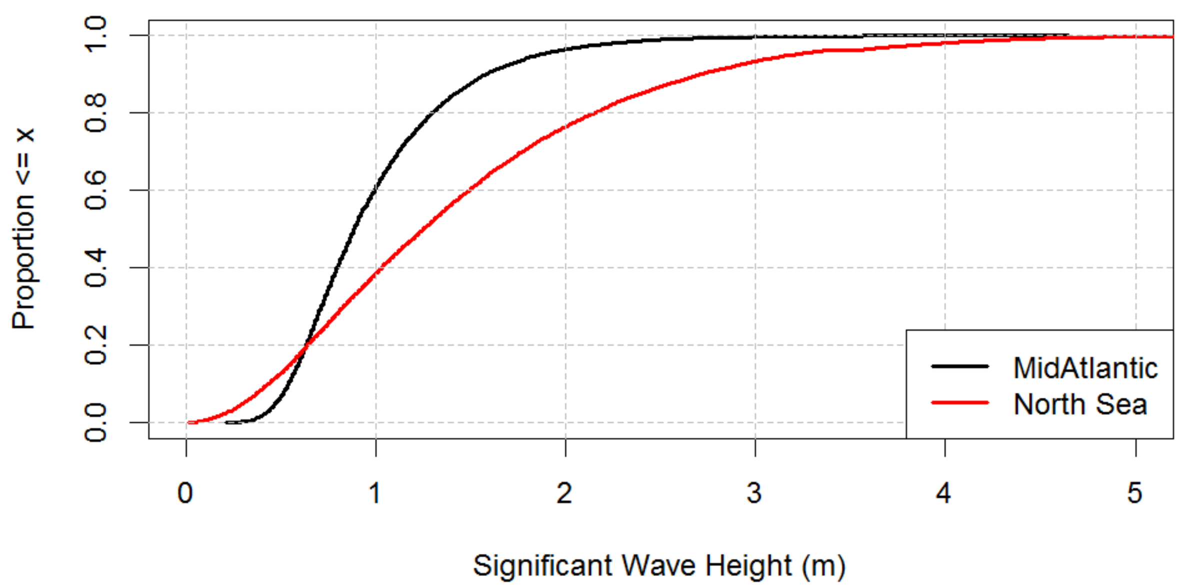

Figure 8. Significant wave height nonexceedance distribution for the mid-Atlantic and North Sea

4.2.5 Spare Part Storage

The baseline scenario assumes that small spare parts are kept in stock in a storage facility in the harbor. This scenario requires no spare part logistics time for replacements categorized in Maintenance Category (MC) 4 (MC4) (small repairs using the turbine crane). The following paragraphs and table address how much extra downtime occurs (in addition to the travel time to the turbine) when small spare parts are not kept in stock onsite, but have to be delivered from the factory.

We varied the logistic time for acquiring the spare parts necessary for MC4 replacements to investigate the effects of not keeping small spares in stock onsite. Because no clear information on realistic delivery times was available, we modeled three scenarios, assuming short, medium, and long delivery times, as outlined in Table 14.

Table 14. Spare part logistic time for a scenario without onsite spare parts

	Spare part logistic time (hours)			
Fault Type Class (FTC)	Baseline	Short	Medium	Long
4	0	24	48	96
5	0	24	48	96
6	0	48	96	168
7	0	48	96	168
8	0	96	168	336

Logistics time is longer for more complex replacements that require more spare parts (e.g., repair scenarios categorized with a higher FTC). The longer the logistics time, the longer the turbine is not available. Failure to keep small parts in stock is expected to decrease availability. It should be emphasized that the baseline scenario did not account for investment in and operational costs of the onsite storage facilities. Therefore, if spare part delivery times are short enough, the lost revenues associated with decreased availability could be less than the investment and operational costs for the onsite storage facilities. More detailed information about the costs for the storage facility and delivery times of spare parts would be required for a more accurate benefit-cost analysis; our results simply emphasize that keeping small spare parts onsite has a positive effect on availability.

It is worth noting that keeping spare parts for large failures (MC6) in stock will not improve availability, because the jack-up vessel, required for transporting these spare parts, has a logistics time of 1 month. Keeping large spare parts onsite can only reduce logistics time when a jack-up vessel is available on short notice or owned by the project operator.

4.2.6 Advanced Condition-Based Monitoring

Advanced condition-based monitoring systems could provide more information on the condition of components, potentially reducing the number of unexpected failures that require corrective maintenance. If the advanced condition-based monitoring system is capable of identifying a possible failure before the component fails, the component can be repaired in a preventative maintenance manner, therefore the turbine can continue to operate for a greater period of time.

Unexpected failures in the drive train contribute significantly to total downtime and O&M costs. These systems are typically subject to the application of condition monitoring systems (for instance, vibration monitoring). To assess the possible benefits of having advanced condition-based monitoring systems on these components, we assumed that a certain percentage of both the MC4 and MC6 corrective failures can be detected by the advanced condition-based monitoring systems. Although the failed (sub)components still need to be replaced, we assume the turbine can continue to operate until the required equipment, spare-parts, and technicians are available to correct the failure(s). This applies to failures in both MC4 and MC6.

As expected, wind plant availability increases with the percentage of failures that can be replaced in a preventive manner. When the condition monitoring systems can prevent 50% of the unexpected failures, availability increases by 1.2% as seen in Table 15. It is important to note that this analysis does not account for the investment and operational costs for the advanced condition-based monitoring systems. It is possible that the advanced condition-based monitoring systems could give false alarms, which may lead to unnecessary inspections, causing additional downtime.

Table 15. Model output as a function of the percentage of corrective failures that can be preventively replaced because of information from condition monitoring systems for the drive train and generator

% of failures that are preventively replaced	Availability [%]	O&M Costs [$/kWh]	Total Effort [M$]
0% (baseline)	84.5	0.0283	86.9
25%	85.1	0.0280	85.3
50%	85.7	0.0278	83.6
75%	86.3	0.0276	82.0
100%	86.9	0.0274	80.4

4.2.7 Summary

Table 16 summarizes the results of each of the O&M strategies investigated. As discussed further in Section 5, even though many of the strategies show promise for reducing LCOE, the benefits could overlap when implemented together (i.e., the improvements to LCOE may not be additive).

Table 16. Quantitative summary of the O&M strategies investigated

O&M strategy summary	Main strategy change compared to baseline	Availability [%]	O&M Costs [$/kWh]	Total yearly effort [M$][7]	Result notes
Baseline O&M scenario	–	84.5	0.0283	86.9	Investment and operational costs for onsite storage are not accounted for in the baseline.
Mother vessel accommodation	Reduced travel time from 2.6 h to 0.5 h. Small parts in stock at mother vessel	91.2	0.0224	62.0	Analysis does not account for mother vessel investment and operations costs.
Helicopter access	Reduced travel time from 2.6 h to 1.0 h. Only for small repairs without spare parts.	87.1	0.0290	82.9	Includes estimated helicopter costs. Does not account for additional turbine investment costs for landing platform.
Vessel contracts	*Parameter stud* Jack-up barge contract Logistics time: 0 to 2200 h MOB/DEMOB costs vary: 0 – 880 k$	83.0 – 85.0	0.0245 – 0.0362	82.3 – 99.4	Assuming clustering of large repairs, a fixed contract is only favorable in scenarios when costs per MOB/DEMOB can be lowered significantly.
Improved crew transfer system	*Parameter study* Access vessel limits Wave height: 0.7 – 3.0 m Wind speed: 12 & 16 m/s	61.3 – 95.3	0.024 – 0.044	56.2 – 153.0	Wave height limit of workboats has large influence on availability and costs. Wind speed limit has very limited influence. Wave height limits greater than 1.7 m have minimal impact on costs.
Spare part storage	*Parameter study* Vary logistics time of part delivery for MC4 repairs: 0 – 336 h	82.3 – 84.5	0.0283 – 0.0290	86.9 – 92.2	Longer logistics times lead to additional costs compared to baseline (i.e., small parts are stored onsite).
Advanced CBM	*Parameter study* Assume Advanced Condition-Based Monitoring for MC4 and MC6, which are subsequently preventively replaced. Detection rate: 0 – 100 %	84.5 – 86.9	0.0274– 0.0283	80.4 – 86.9	If a larger percentage of failures can be detected by Advanced CBM systems the availability increases and costs decrease. Analysis did not account for investment and operational costs for Advanced CBM systems. Additional costs due to false alarms not considered.

[7] Total O&M effort numbers presented in this report represent the sum of revenue losses and accrued O&M costs on a yearly basis. The $/kWh O&M costs, however, do not include the direct cost of revenue losses. Rather, the impact from loss of revenue on a $/kWh basis is accounted for via the change in energy production.

5 Preferred IO&M Case Study

This chapter outlines our approach to developing a preferred IO&M strategy for use in a case study. Specifically, we:

- Analyzed combined installation strategies to establish a preferred installation strategy
- Analyzed combined O&M strategies to establish a preferred O&M strategy
- Assessed the tradeoffs between O&M costs and associated installation costs and energy production to establish a preferred IO&M strategy.

5.1 Preferred Installation Strategy

Of the installation strategies that we investigated, only two showed installation cost reductions compared to the baseline: division of turbine assembly tasks between onshore and offshore, and changes to foundation and electrical installation approaches.

We evaluated the impacts of changing the foundation and electrical installation approaches by conducting a sensitivity analysis (i.e., we evaluated how much installation costs would change for a given change in electrical installation cost or foundation installation time). We did not identify specific technologies or process innovations that would lead to these changes, however, so we did not include changes to foundation and electrical approaches in our preferred installation strategy.

As described in Section 4.1.1, we evaluated six different turbine assembly methods, distinguished by how much of the turbine is installed onshore versus offshore. Although the bunny ears with 1-part tower assembly method was the lowest cost option, some turbine manufacturers may not allow the bunny ears style installation method because transportation of the turbine in that unique configuration could lead to increased, or at least uncertain, loads on components. Consequently, the bunny ears style installation method was ruled out for the preferred case. The next lowest-cost assembly strategy was the pre-assembled rotor with one part tower, which we selected as the preferred installation strategy.

Table 17 shows the total BOS costs for the case study that assumes the preferred installation strategy (pre-assembled rotor with one part tower turbine assembly) is used. Utilizing this turbine assembly method, the total preferred BOS cost ($2,550/kW) is 5% lower than the total baseline BOS cost ($2,682/kW).

Table 17. Preferred BOS cost items

Preferred BOS Cost Item	**($/kW)**	**($/kWh)**
Development	118	*0.0038*
Ports and Staging	79	*0.0026*
Support Structure	800	*0.0259*
Electrical Infrastructure	498	*0.0161*
Installation Vessels	1055	*0.0341*
Total	**2550**	**0.0825**

5.2 Preferred O&M Strategy

Individually, a number of the O&M strategies we evaluated offer potential to improve both the wind plant availability and the O&M costs for the baseline scenario. We sought to identify which combination of these O&M strategies would lead to the greatest reduction in cost compared to the baseline. In this section, we describe how we combined the strategies and selected a preferred O&M strategy as input for comparison in a preferred IO&M strategy.

The two O&M strategies with the highest potential to improve availability and reduce revenue losses are: investment in an improved crew transfer system (e.g., application of a workboat with less restrictive weather limitations), and using a mother vessel to provide accommodation at the wind plant instead of daily transfer from the harbor.

Both strategies focus on a reduction of the waiting time caused by bad weather conditions, which is the primary driver for the low wind plant availability in the baseline scenario. Individually, each of these strategies has the potential to reduce the total O&M effort from the baseline by more than $20 million. Other O&M strategies (helicopter access and advanced CBM) also yielded improvements, albeit much smaller than for the improved crew access system and mother vessel accommodation. On the other hand, ordering spare parts directly from the factory, rather than storing them onsite, causes longer downtimes and could decrease availability compared to the baseline.

These findings suggest that an improved crew access system in combination with a mother vessel accommodation would be the preferred O&M strategy. However, because each strategy addresses the waiting time caused by bad weather conditions, we cannot assume that the total improvement compared to the baseline equals the sum of the individual strategies. We evaluated the cost savings associated with an improved crew access system (compared to the baseline) as well as the cost savings associated with four other scenarios (various combinations of an improved crew access system, plus one additional O&M improvement strategy).

To identify a preferred O&M strategy, we first had to establish the capabilities of an improved crew transfer system and calculate the wind plant availability for different weather windows (combinations of significant wave height and wind speed). For the preferred O&M scenario, we assume that the workboats used can operate up to a significant wave height ($H_{s,max}$) of 1.5 m and maximum wind speed (V_{max}) of 12 m/s. These limits are typically valid for workboats used for maintenance of offshore wind plants in Europe (Obdam & van der Zee, 2011) and are therefore considered realistic for use in the U.S. market, if the vessels were built in or relocated to the U.S. We also assume that the travel speed of the improved workboat is equal to the baseline workboat (one-way travel time is 2.6 h). However, because of the workboat's improved capabilities, it is also expected that the day rate for the improved workboat will be higher compared to the baseline. As a best estimate, we assume an increase in cost of 25%, which results in a day rate of $2,500.

The additional four strategies we evaluated were composed of this specific improved crew transfer system scenario, which employs these specific work boat specifications (step 1), plus one of the O&M strategies below:

- Variation A: Mother vessel
    - Travel time of the workboats is reduced from 2.6 to 0.5 h because they are launched from the mother vessel.
    - An offshore premium of $175/h is taken into account for the technicians who, in this scenario, must live and work offshore for a prolonged period of time.
- Variation B: Jack-up barge owned by project
    - The mobilization and travel costs for the jack-up vessel are set to zero, because it is no longer rented from the spot market.
    - Only an estimation for the OPEX, related to the jack-up being applied for O&M purposes, is made because a more detailed modeling of a project-owned jack-up vessel is needed, which is performed in Section 5.3.
    - No logistic time is considered for the jack-up barge.
- Variation C: Helicopter access
    - Crew transfer for small repairs and inspections is done by helicopter.
    - Helicopter access is not limited by wave height.
    - Additional capital expenses (e.g., helicopter access at each turbine) are not considered.
- Variation D: Advanced condition-based monitoring
    - Employing advanced CBM, we assume 50% of medium and large corrective repairs on the drivetrain system can be avoided with preventive maintenance.
    - For these repairs, the turbine is only shut down during the actual replacement.

Using a two-step approach, we evaluated the preferred O&M strategy. First, only the improved workboats are included as the initial preferred O&M strategy. Next, the other strategies are added as variations to the initial preferred O&M strategy to evaluate their potential for further cost reduction. A summary of the results is presented in Table 18, and a detailed summary of downtime and O&M costs for the assessment of O&M strategies is given in Appendix F.

Table 18. Summary of O&M strategies studied with highest improvement opportunity

O&M strategies	Availability [%]	O&M Costs [$/kWh]	Total yearly effort [M$][8]	Result notes:
Baseline O&M scenario	84.5	0.0283	86.9	This is the baseline O&M scenario
Step 1: *Improved crew transfer*	**93.3**	**0.0248**	**62.1**	**Significant effect compared to baseline: total O&M decreased by $24.8M.**
Step 1 + Variation A: *Mother vessel*	95.2	0.0223	53.3	Analysis does not account for increased cost of mother vessel [indication: $15M - $20 M/year when rented from spot market, (BVG Associates, 2012)]
Step 1 + Variation B: *project-owned jack-up vessel*	93.8	0.0180	48.8	Accounts for changes in operating expenses, but not capital cost of project-owned jack-up vessel.
Step 1 + Variation C: *Helicopter access*	93.9	0.0260	63.3	Increased operational costs. Does not account for additional turbine investment costs for landing platform.
Step 1 + Variation D: *Advanced CBM*	93.7	0.0247	61.1	Results shown are for 50% detection rate with 0% false alarms. Does not account for investment and operational costs for CBM systems.

Using only the improved access system (workboats capable of operating up to 1.5 m significant wave height) results in savings of approximately $24.8 million annually compared to the baseline, which is a result of the greatly reduced waiting time caused by bad weather conditions. It should be noted that these significant savings are realized because the baseline work boat was chosen to reflect the currently available work boats in the United States, which are optimized for

[8] Total O&M effort numbers presented in this report represent the sum of revenue losses and accrued O&M costs on a yearly basis. The $/kWh O&M costs, however, do not include the direct cost of revenue losses. Rather, the impact from loss of revenue on a $/kWh basis is accounted for via the change in energy production.

the offshore oil and gas industry, not the offshore wind industry. If the offshore wind industry were to grow significantly in the United States, it would be reasonable to assume that even first-of-a-kind wind plants would use work boats similar to those in Europe (with a 1.5-m significant wave height). However, because they are not currently available in the United States, this type of workboat was not considered for the baseline.

The results for Variation A (improved crew access system plus use of a mother vessel) indicate that additional savings of around $9 million can be expected when the maintenance is organized from a mother vessel, because this strategy further reduces travel times. When a mother vessel is rented from the spot market, estimates of annual costs fall between $15 million and $20 million (BVG Associates, 2012), which indicates that for the selected wind plant location the use of a mother vessel will be prohibitively expensive. For wind plants located further offshore, the use of a mother vessel will likely be part of the preferred O&M strategy. It was beyond the scope of this analysis to identify the cross over point at which the distance from shore is great enough that the costs of a mother vessel are offset by the savings from reduced travel time between the wind plant and harbor. To accurately evaluate at which distance from shore this turning point lies, time series data with wave height and wind speed for a number of locations with different distances from shore would be needed because these parameters can vary significantly from one location to the next.

The results of Variation B (improved crew access system plus a project-owned jack-up vessel) indicate potential cost savings of approximately $13.3 million compared to Step 1 (jack-up vessel is rented from the spot market). These findings assume that no variable costs other than OPEX are incurred for the jack-up vessel and that the jack-up vessel is always available (logistics time is equal to 0 h). If the project-owned jack-up vessel is also suitable for the wind plant installation and decommissioning phases, larger cost savings are possible. However, this method also requires a more detailed assessment of the investment costs for such a vessel. Operational costs must be considered when the vessel is also applied for the installation and decommissioning phases, as well as when the vessel is in standby or idling. To better assess whether the use of a project-owned jack-up vessel is a cost-effective solution, we conducted a separate, more detailed assessment presented in Section 5.3.

The results for Variation C (improved crew access system plus helicopter access) show that having helicopter access for small repairs and inspections will slightly improve wind plant availability, but will also lead to higher costs. The reduced revenue losses do not offset the higher costs of repair with the helicopter; the total O&M costs will increase by approximately $1.1 million. The main reason for this is that accessing the turbine via helicopter is not feasible for repairs that require the delivery of spare parts. It is worth noting that operating helicopters will also require the addition of landing platforms for the technicians on the turbines; these are additional costs that we did not account for in our analysis. For wind plants located further offshore, the use of a helicopter may have a positive effect on the total O&M effort. As with the analysis of the mother vessel, to accurately evaluate at which distance from shore this cross over point occurs, it is necessary to have time series data with wave height and wind speed for a number of locations with different distances from shore. These data are needed because the wind and wave conditions affect decisions about which vessel (or helicopter) to employ for a given repair and affect the timing of those repairs.

The analysis for Variation D (improved crew access system plus the installation of advanced condition based monitoring systems at the drive train and generator systems), shows that if more than 50% of the medium and large replacements on both systems can be detected, at least $1 million annually could be saved compared to the Step 1 scenario (improved crew access system only). This cost savings estimate does not account for the costs associated with additional inspections caused by false alarms or the investment costs for the actual monitoring systems. It is worth noting that we do not know whether a target of 50% failure prediction can be achieved by these systems; 50% was used as a best estimate given our current understanding of CBM systems. Taking these caveats into account, we chose not to include advanced condition-based monitoring in the preferred IO&M strategy.

Our analysis indicates that including the improved workboats, possibly coupled with a jack-up vessel owned by the project (Variation B), is the preferred O&M strategy. The possible advantages of a project-owned jack-up vessel are discussed in more detail in Section 5.3.

5.3 Project-Owned Jack-Up Vessel

The use of a project-owned jack-up vessel for the operational, installation, and decommissioning phases could offer an opportunity for substantial cost savings. We assessed the potential IO&M cost savings over the assumed 20-year lifetime of the baseline wind plant. The cost savings for installation, decommissioning, and operational phases include the OPEX for the jack-up vessel, and total approximately $307 million. The savings can be broken down as follows:

- Installation and decommissioning phase (NREL BOS model): $ 40,856,000
- Operational phase (ECN O&M Tool v4.4): $ 266,164,000

To provide net savings to an offshore wind project, the approximate $307 million in savings will have to offset the costs of a project-owned jack-up vessel, which are composed of both:

- CAPEX: Principal and interest on debt to cover initial capital outlay
- OPEX: Vessel operating expenses, consisting of personnel, fuel costs, insurance, and administrative costs when the vessel is idling (i.e., when the vessel is standby and not applied for IO&M purposes).

Our estimate of the jack-up vessel CAPEX for the assumed 20 years of lifetime[9] included the following assumptions, based on information supplied in (RWE Innogy) and (Kaiser & Snyder, 2010):

- The vessel investment costs are $120 million and are financed through a cash payment of 20% and a loan of 80% over 10 years with a 5.5% yearly fixed interest rate (assuming monthly principal payments).
- The vessel is operated in-house by the project owner, thus the ROI is set at 0%.

[9] After 20 years, the vessel is assumed to be fully depreciated.

The total CAPEX estimate for the 20 year project lifetime is calculated as follows:

$$CAPEX_{20y} = \$120{,}000\,\mathrm{k} + \sum_{i_{month}=1}^{i_{month}=120} \left\{ \left(121 - i_{month}\right) \cdot \left(\frac{0.8 \cdot \$120{,}000\,\mathrm{k}}{120} \right) \cdot \frac{0.055}{12} \right\} \Rightarrow$$
$$CAPEX_{20y} = \$146{,}620\,\mathrm{k} \tag{5.3-1}$$

The OPEX for IO&M are accounted for in the \$307 million cost savings for IO&M. However, in practice, when a vessel is owned by the project, the project owner would incur additional OPEX when the vessel is not being used for IO&M, i.e., when the vessel is idling. We estimated the OPEX for idling by assuming a day rate of \$38,750 when the vessel is waiting for a suitable weather window to perform repairs.[10] We assume the vessel is idling for all days in the 20-year project lifetime that it is not being used for O&M (1101.4 days) or for installation and decommissioning (819.5 days; 454 days for installation, plus 365.5 days for decommissioning). The total number of days during the 20-year project lifetime is 7305 days (including 5 leap days). Total OPEX for idling is:

$$OPEX_{idling} = \left(N_{days\,20yr} - N_{days\,O\&M} - N_{days\,Install/Decomm}\right) \cdot \text{day rate} \Rightarrow \tag{5.3-2}$$
$$OPEX_{idling} = \left(7305 - 1101.4 - 819.5\right) \cdot \$38.75\,\mathrm{k} = \$208{,}634\,\mathrm{k}$$

The total costs associated with a project-owned jack-up vessel during the 20 years of wind plant lifetime are estimated to be approximately \$355 million—the sum of the CAPEX and OPEX as estimated in equations (5.3-1) and (5.3-2). This cost estimate is \$48 million higher than the estimated cost savings of \$307 million. Given the assumptions that we applied to our analysis of this particular 500-MW wind plant, the total lifetime costs outweigh the benefits of investing in a project-owned jack-up vessel. During the O&M phase of the wind plant, the jack-up vessel is only utilized for O&M activities approximately 15% of the time; we assume it would remain idle the remaining 85% of the time.

There are significant costs associated with the project-owned jack-up vessel when the vessel is idling, because its deployment for IO&M purposes is moderate with an average utilization of 26.3% during the project's lifetime of 20 years. A portion of the jack-up's idling OPEX may be recovered if it could be used (and paid for) by other projects (i.e., by renting the vessel to other projects/wind plants). However, even though utilization of the vessel at additional locations would decrease idling time, it could introduce logistics time (the time for the vessel to complete its other job and travel back to the owner's wind plant again). The preferred O&M strategy, however, assumed logistics time would be zero (because the jack-up vessel would always be available); therefore, the actual cost savings would be less than the estimates presented in the previous section. Additionally, the idling OPEX still have to be paid for the days when it is not possible to rent the vessel to other projects or wind plants. A more in-depth analysis of this tradeoff for the jack-up vessel is beyond the scope of this report. Opportunities may exist for

[10] For the estimation on the day rate in (Obdam & van der Zee, 2011), it is assumed that only 75% of the commercial day rate is charged when the vessel is waiting for a suitable weather window to perform repairs. This 25% reduction of the day rate, or \$38.75k is assumed to be fully attributed to a reduction in OPEX (e.g., by reduced fuel and personnel costs) and is translated to a 50% reduction of the OPEX for the jack-up when waiting/idling.

wind plant operators and/or third parties to operate and rent their own jack-up vessels if the vessel can be applied to more or larger offshore wind projects.

5.4 Preferred IO&M Strategy

Based on the findings presented in Sections 5.1 to 5.3, the preferred IO&M strategy for the case study involves the method of installing the turbines in a pre-assembled rotor with one part tower, and investing in improved work boats (for crew access to the turbines) that can operate in higher sea states.

We calculated annual energy production estimates using the ECN O&M Tool (Obdam, Braam, & Rademakers, 2011) on a seasonal basis using the same wind data set used for the waiting and downtime analysis, detailed in Appendix A. The LCOE for the case study using the preferred IO&M strategy is $0.20/kWh, as shown in Table 19.

Table 19. Summary of preferred LCOE

		($/kW)	($/kWh)
Turbine Capital Cost		1800	0.0582
	Development	*118*	*0.0038*
	Port and Staging	*79*	*0.0026*
	Support Structure	*800*	*0.0259*
	Electrical Infrastructure	*498*	*0.0161*
	Installation Vessels	*1055*	*0.0341*
Balance of Station		2550	0.0825
	Insurance	*87*	*0.0028*
	Decommissioning	*380*	*0.0123*
	Contingency	*435*	*0.0141*
Soft Costs		902	0.0292
Overnight Capital Cost (OCC)		5252	0.1699
	Construction Financing	*158*	*0.0051*
Installed Capital Cost (ICC)		5409	0.1750
O&M ($/kW/yr)		767	0.0248
Net Annual Energy Production (AEP) (MWh/MW/yr)		3648	
Fixed Charge Rate (FCR)		11.8%	
Levelized Cost of Energy ($/kWh)		**0.200**	

6 Conclusions

Installation, operation, and maintenance are expected to account for nearly one-third of offshore wind LCOE in the United States. Consequently, there is a large potential for reducing LCOE through advanced IO&M strategies. After investigating several IO&M strategies (listed in Table 20) we found that a combination of one of the installation strategies and one of the O&M strategies would prove to have the greatest impact on LCOE.

Table 20. Advanced IO&M strategies

Installation Strategies	O&M Strategies
Land-based vs. offshore assembly	Mother vessel accommodations
Direct delivery of components	Helicopter access
Purpose-built installation vessel	Vessel contracts
Reduced electrical and foundation installation	Improved crew transfer system
	Spare part storage
	Advanced CBM

The preferred IO&M strategy for the case study included:

1. **A specialized turbine assembly procedure**; instead of assembling the turbine offshore as individual components, the rotor would be pre-assembled in port before load-out for installation. Additionally, the tower would be assembled in port so that only a single offshore lift would be necessary.
2. **Improved workboat for crew transfer;** use of this improved work boat (an advancement in the O&M phase of the project) would reduce waiting time caused by weather, by increasing the allowable working sea state from a significant wave height of 0.9 m to 1.5 m.

The preferred turbine installation strategy had an effect on two primary LCOE categories: ports and staging, and vessels. Compared to the baseline, the ports and staging costs increase in the preferred installation strategy because of the increased storage area needed for the pre-assembled rotors (their packing density is significantly less than that of individual components). The ports and staging costs also increase because of the additional work conducted at the port (the rotors and towers are assembled at the staging port). However, because the preferred installation strategy requires less offshore assembly, the overall vessel costs are lower than in the baseline scenario. Vessel costs are reduced by $185/kW (15% less than the baseline vessel costs), which more than offsets the increase in port and staging costs.

The preferred O&M strategy lowered overall O&M costs by $0.0035/kWh (12%), primarily because the increased sea state limits of the improved workboats, allowed for significantly reduced waiting periods caused by wind and wave conditions. This reduction in waiting time has a substantial impact on availability, and therefore energy production, raising AEP by almost 400

MWh/MW per year—an increase of more than 10% compared to the baseline. This increase in AEP is the primary contributor to the overall reduction in LCOE seen in Table 21.

Table 21. Improvements in LCOE through the preferred IO&M strategy

	Baseline	Preferred	Impact
AEP (MWh/MW/yr)	3267	3648	+11.7%
Availability	84.5	93.3	+10.4%
O&M ($/kWh)	0.0283	0.0248	-12.4%
Ports & Staging ($/kW)	26	79	+304%
Installation Vessels ($/kW)	1240	1055	-15%
LCOE ($/kWh)	**0.233**	**0.200**	**-14%**

The IO&M improvements applied to the case study reduced LCOE by 14% compared to the baseline; specifically, our LCOE estimate declined from $0.233/kWh (in the baseline) to $0.200/kWh (in the case study with a preferred IO&M approach). This 14% reduction in LCOE is primarily attributable to the increase in AEP and is a strong indicator that careful planning and analysis of IO&M strategies can significantly reduce LCOE.

6.1 Disclaimer

All data and results presented in this study (among others: failure data, vessel capabilities and costs, repair strategies, and wind turbine specifications) are indicative of averages and should not be taken as absolutes. Although the authors have attempted to use figures that are representative of contemporary large offshore wind plants, readers must always use their own data, applicable to their own situation. However, the data in this document can be used as a starting point with the relative changes associated with each strategy providing useful insight into overall trends.

As discussed earlier in the report, a number of assumptions were made that heavily influence the results of the analysis. In the event that any of the assumptions are altered, depending on the importance of the assumption and how much it is varied, the conclusions of this study may be substantially different. In some cases, changes in a single assumption can alter the LCOE by ±50%. Section 4.2.4 demonstrates an example of this using wave heights and indicates how simple changes in assumptions can lead to significant differences in conclusions.

6.2 Recommendations for Future Work

The authors of this study have attempted to use data that are representative of large offshore wind turbines and plants that are expected to be built off the shores of the United States in the near future. Continued work focusing on how the underlying assumptions and unknown capital costs impact the conclusions is important. By expanding the work to look at the impact of the underlying assumptions, the results can be more useful to the offshore wind industry because of the more universal nature of the results. Additional efforts to look at unique installation methods for electrical and foundations would likely prove valuable, based on the initial results seen in this study. Furthermore, estimating the "break even" points for various technologies may be valuable.

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Appendix A. Wind and Wave Data

For the analysis of waiting time caused by bad weather conditions for the wind plant, a series of meteorological data were used. For this analysis, 120 months of Wavewatch III hindcast data files covering the period from 01-Jan-2000 through 31-Dec-2009 for the WIS grid point 63198 were used.

The files included a timestamp, wind speed (at 10 m), wind direction, significant wave height and wave period. For the analysis described in this report, only the timestamp, wind speed and significant wave height were used. The files came with a 1-hourly sample rate. However, MS-Excel 2003 and earlier can only handle 65536 rows, which made it impossible to include all data. Therefore, the 1-hourly data were transformed to 3-hourly data to ensure the full 10-year period could be included in the analysis. The conversion was done by simply taking the average over every 3 h in the original dataset.

Subsequently, the WaitingTime module of the ECN O&M Tool was applied to determine the average waiting time (because of bad weather) as a function of the mission time. This is done for the weather windows listed in Table 22. As shown in the table for certain weather restrictions, in fact, two weather windows were defined: one for a normal working day (Lwd = 0 = 12 h) and one for a long working day (Lwd = 1 = 24 h).

Table 22. Weather windows for which the relation between waiting time and mission time is calculated

weather window	weather restrictions				day
	Hs	Vw			Lwd
1	**2.5**	**10**	**0**	**0**	**0**
1	2.5	10			0
2	2.5	10			1
3	0.9	12			0
4	0.9	12			1
5	1	25			0
6	2	25			0
7	0.9	10			0
8	0.9	8			0

The results of the calculation are presented as 2nd and 3rd order polynomials. An example of such a relation is shown in Figure 9.

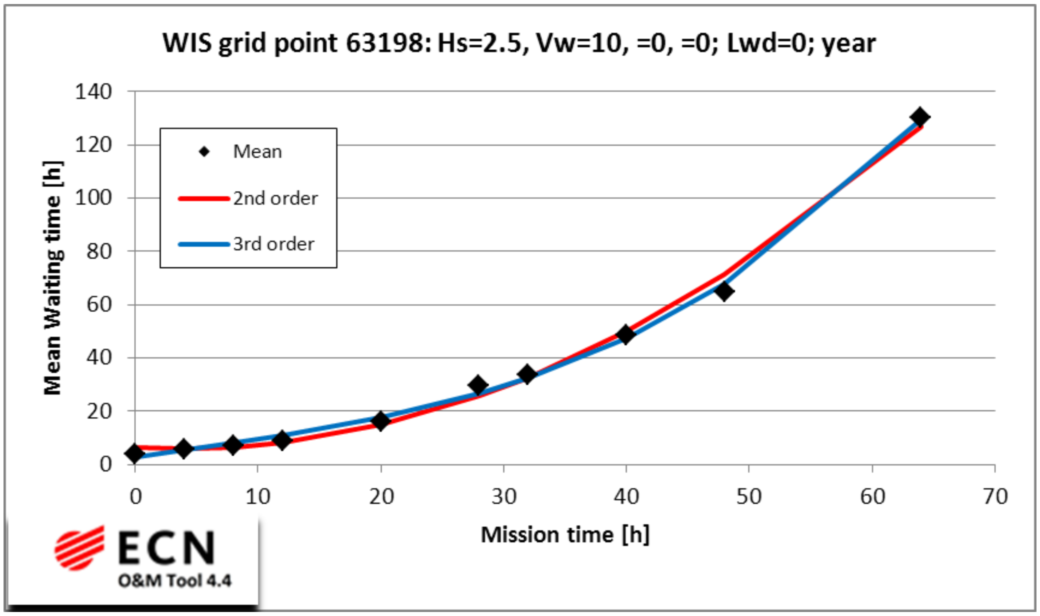

Figure 9. Example of the calculated relation between waiting time and mission time as determined using the WaitingTime module for the jack-up barge—yearly average for weather window no. 1

Besides the results over a period of 10 years, the four yearly seasons are also considered separately, and are defined as follows:

- Winter: December, January, February
- Spring: March, April, May
- Summer: June, July, August
- Autumn: September, October, November.

To obtain more insight into the results of the waiting time calculations, some additional analyses were performed. Initially, a comparison was made between the yearly average calculated relation between waiting time and mission time for different weather windows (see Figure 10).

First, it can be seen that for the two "sets" of weather limits (1-2 and 3-4, see also Table 22) the weather window (WeWi) applicable for the normal working day (WeWi 1 and 3) yields longer waiting times compared to the weather window applicable for the long working day (WeWi 2 and 4). This is expected, because the calculations take into account that a suitable weather window can only start during the working day. Also, see section 5.3.2 in (Obdam, Braam, & Rademakers, 2011).

Second, it can be observed that for WeWi 8 the longest waiting times will occur. It is noticed that the difference is very small between the waiting times of WeWis 3 and 7, although there is a 2-m/s lower wind speed limit for weather window 7. WeWi 8 has a similar wave height limit, as set by the capabilities of the workboat, yet has an even lower wind speed limit set at 8 m/s. This clearly results in longer waiting times, as seen in Table 22.

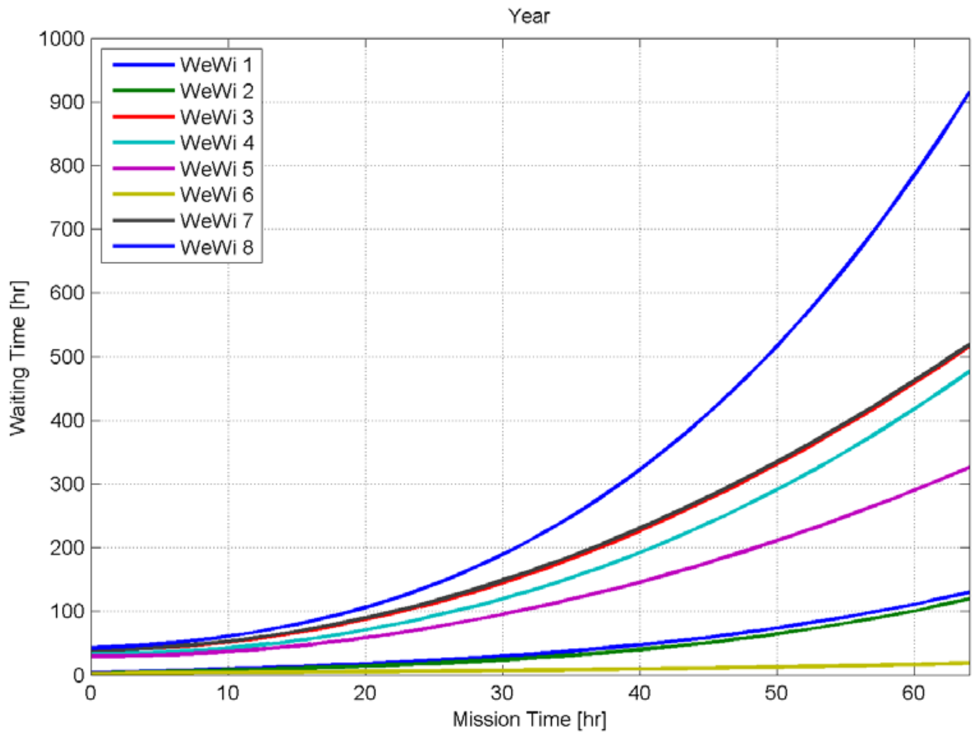

Figure 10. Waiting time as a function of mission time for the eight defined weather windows

In addition to the estimation of average waiting time (caused by bad weather conditions) the meteorological data were also used to derive the wind climate in the wind plant. The wind climate information is necessary to estimate the wind plant capacity factor, which again is used to make estimations of the lost revenues associated with downtime (Obdam, Braam, & Rademakers, 2011). By applying MATLAB commercial software, the wind climate is characterized by a Weibull-fit, including scale parameter A and shape parameter k. Whereas for the waiting time analyses the 3-hourly data were used, for deriving the Weibull parameters the 1-hourly wind speed data were used. (For wind resource assessment, usually 10-minute or 1-hourly data are used.) The yearly average wind speed distribution, including the associated Weibull approximation, is shown in Figure 11.

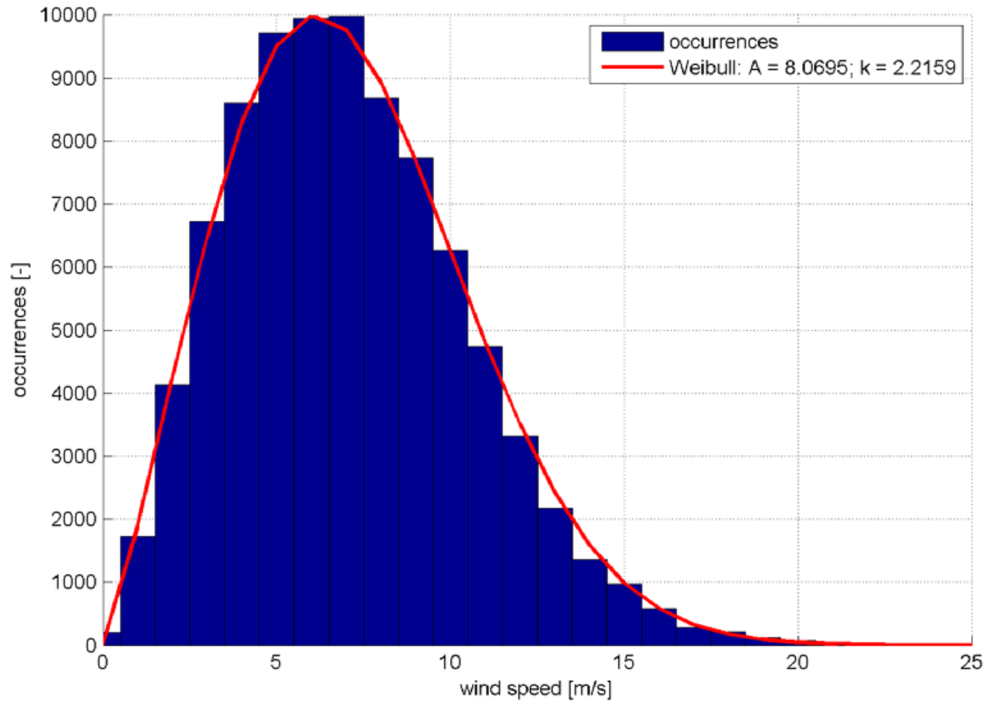

Figure 11. Yearly average wind climate at 10-m height, as derived from the 10 years of hourly wind speed data

Similar to the yearly average wind speed distribution, Weibull-fits are made for the spring, summer, autumn, and winter seasons. The results for the Weibull approximations are given in Table 23 below.

Table 23. Weibull parameters per season at 10-m height, as derived from the hourly wind speed data

Weibull parameters at	10	*m*
Season	**shape**	**scale**
Winter	2.46	9.49
Spring	2.34	8.24
Summer	2.49	6.52
Autumn	2.11	8.01
Year	2.22	8.07

Appendix B. NREL BOS Model Overview

Overview

To model capital expenditures associated with installation activities and other BOS cost items, NREL used and further developed its offshore BOS model. The model was built on data provided by GL Garrad Hassan in a report that investigated the major contributions to offshore wind-project BOS costs in the United States (GL Garrad Hassan, 2012). The data covered the key cost drivers and trends, and provided typical values, expected ranges, and assumptions made based on today's technology and best practices. Because of the immature nature of the U.S. offshore wind market and high level of uncertainty in specific cost elements, budgetary level costs were provided at a moderate level of detail. In compiling the information contained in the report, GL Garrad Hassan drew from its active participation in offshore wind projects in Europe, along with its experience in the onshore wind industry in the United States.

Through the work completed in this study, a few components of the BOS model have been updated. The primary sections of the model that have been updated are the Installation Vessel and Decommissioning sections. The data necessary for these updates come from both the GL Garrad Hassan report and a number of other data sources (BVG Associates, 2012), (Douglas-Westwood, 2012), (GL Garrad Hassan, 2012), (Kaiser & Snyder, 2010), and (Uraz, 2011).

Development

Development costs in the BOS model encompass the work completed by a wind project developer up to the works completion date. For each of the categories considered in development costs, a high, low, and typical value is available for use. Ranges between the high and low values for some of the cost items can range by factors of nearly 100. Because of the high uncertainty of the U.S. market, for this study, the typical value was used. In its current operational state, the model simply adds up all of the development cost components and does not have any dependency on project parameters. A list of primary cost categories included in development costs are presented below.

- Project management
- Front end engineering design (FEED) and Pre-FEED studies
- Detailed engineering design of the support structure
- State and outer continental shelf (OCS) leasing process
- Site assessment plan
- Construction operation plan
- National Environmental Policy Act (NEPA) environmental impact study (EIS) for met tower and project
- Physical and biological resource studies for the met tower and project

- Socioeconomic, land use, navigation, and transportation studies for the meteorological tower and project
- Federal Aviation Administration (FAA) studies
- Coastal Zone Management Act (CZMA) consistency
- Rivers and Harbors Act, Clean Water Act, Endangered Species Act, Marine Mammal Protection Act, Migratory Bird Treaty Act, and National Historic Preservation Act compliance
- Additional state and local permitting.

Port and Staging

Port and staging costs in the offshore BOS model are based entirely on the data provided by GL Garrad Hassan (GL Garrad Hassan, 2012). As with other sections of the model, there are high, low and average costs provided for each of the port and staging cost components. Below are the primary cost components that the port and staging module includes.

- Wind turbine and support structure storage area
- Port entrance and exit fees
- Quayside docking fees
- Wharfage costs
- Port cranes including self-propelled modular transport units (SPMTs), crawler and tower cranes.

To calculate the entrance, exit, docking, and wharfage costs, the port and staging module analyzes how many trips are taken by each of the installation vessels, based on the installation strategy utilized. For the storage area costs, the module looks at total storage area and the time for storage. To calculate the storage area, the module makes assumptions about blade, nacelle, and tower dimensions based on turbine rating. Then, based on the installation strategy, it calculates the total storage area required, including clearance allocations. The crane costs are set constant, assuming that the necessary cranes are on site and paid for throughout the entire project, regardless of usage.

Support Structure

The BOS model calculates the support structure as three primary pieces for the monopile structure: primary steel, secondary steel, and transition piece. For the primary steel, a mass is calculated based on a simple scaling relationship that is dependent on turbine rating and water depth. From the calculated mass of the primary steel, an average cost per tonne (average between high and low estimate) is applied to generate a cost for the primary steel. Calculations for the secondary steel are carried out in the same manner with specific scaling relationships and costs. Transition piece mass relies on a scaling relationship based solely on the turbine rating, then the model applies that mass to a cost per tonne. Size dimensions, such as length, width, etc. are not used in the support structure module; however, they are used in the port and staging module and therefore are calculated there.

Electrical Infrastructure

Electrical infrastructure costs are binned in three primary cost buckets in the offshore BOS model: array cable, export cable, and offshore substation.

Array Cable

The array cable cost module is currently capable of calculating array cable costs and requirements for only a radial cable layout and two cable sizes. Based on the turbine rating and the cable electrical capacity, the number of turbines that can fit on one string is determined. The number of turbines on one string, number of turbines, and array spacing all factor into the calculated length of array cable needed. With an average array cable cost per meter (average between high and low estimate) and ancillary costs per turbine and substation interface, a total array cable cost is determined. The installation of the cables is calculated on a $/km basis; however, this calculation is performed in the installation vessels module.

Export Cable

Export cable costs are calculated in the same manner as the array cable, with the exception that additional landfall expenses must be taken into account. Simple, single-cost estimates for the following landfall expenses are made by the model.

- Horizontal directional drilling
- Multi-purpose marine vessel rental
- Dive team
- Winch rental and operation
- Transition joint civil and electrical work.

Offshore Substation

Primary costs for the offshore substation components are based on estimates for a 500-MW wind plant and are not scaled to or from another plant size. The offshore substation is expected to be built at a dockside construction yard and transported and installed by a heavy-lift vessel. This installation cost is accounted for in the installation vessels module. The cost of the offshore substation is calculated by applying costs for the primary substation components, listed below, and totaling them.

- Main power transformers
- High voltage switchgear
- Medium voltage switchgear
- Back-up generator
- Ancillary systems
- Workshop, fire protection, accommodations, etc.

Installation Vessels

A complete spread of installation vessels is modeled in the offshore BOS model. For the six installation strategies investigated in this study, the vessel spread may change slightly, based on the lifting requirements of each strategy. Because it is beyond the capabilities of the model to understand when the exact periods of weather downtime occur, the model assumes that all installation vessels in the spread are contracted for the entire length of the construction period. Weather downtime is, however, calculated to demonstrate its relative impact on offshore installation operations by establishing a nonexceedance distribution based on wind and wave restrictions for each vessel and operation. An example of this distribution is presented in section 4.2.4. Based on the nonexceedance distribution and the restriction of the vessel or operation, an average waiting time is assigned and added to the overall installation time. Vessels considered for the installation (and decommissioning) are listed below.

- Heavy lift vessel (2000 tonne and 5000 tonne)
- DP2 heavy lift cargo vessel
- Jack up vessel
- Offshore barge
- Seagoing tug (100 tonne)
- Anchor handling tug (120-, 150-, and 200-tonne class)
- Dredging vessel
- Rock dumping vessel (for scour protection)
- Crew transfer vessel (12 person)
- Grout spread vessel
- Sheerleg crane barge
- Work class ROV
- Survey boat
- Cable-laying vessel
- Wind plant security vessel.

Decommissioning

Decommissioning activities are modeled in the offshore BOS model in the same manner as the installation but in reverse order and with a few key differences. Based on information presented in (BVG Associates, 2012) and (Kaiser & Snyder, 2010) the following assumptions are assumed to be the only differences between installation and decommissioning.

- Select activities have a reduced time associated with them because of the decommissioning process having fewer restrictions that are necessary in installation to protect the components from getting damaged.

- Cable removal utilizes an offshore barge and 100-tonne seagoing tug instead of a cable installation vessel. Cable removal time is also reduced 10%.
- Vessel costs are reduced to the minimum vessel day rate because decommissioning has a much more flexible schedule.
- Ultra-high power water jet cutting equipment is required for the removal of the monopile.
- No scour protection removal is needed.

Appendix C. Detailed O&M Assumptions

General Wind Plant Data

The general wind plant data used for the modeling are listed in Table 24 below. Note that the kWh price in the Wind Farm Data table is the assumed power purchase agreement (PPA) price, which is used in the "lost revenue" calculations. The PPA price of $0.125/kWh was chosen because it was representative of the region's current end consumer price. In reality, PPAs for first of a kind offshore wind plants will most likely be higher than the one chosen in this study.

Table 24. General data for the U.S. baseline wind plant

Wind Farm Data		
Name of wind farm		
U.S. baseline IO&M case study		
Miscellaneous		
kWh price	0.125	USD
Number of turbines	100	-
Lifetime	20	years

WT Characteristics		
Type Windturbine		
NREL offshore 5-MW baseline		
General data		
P_rated	5000	kW
Investment costs	1800	USD/kW

Capacity factors	
Season	
Winter	56%
Spring	47%
Summer	32%
Autumn	44%
Year	45%

Weighing factors fail. freq.	
Season	Weigh. Factor
Winter	0.25
Spring	0.25
Summer	0.25
Autumn	0.25

All general information is based on discussions between ECN, NREL, and the Expert Panel. The capacity factors were calculated with the ECN O&M Tool, where the Weibull coefficients describing the wind climate were derived with from the same time series that were used to assess the waiting time caused by bad weather conditions.

All year long a crew of 70 technicians is employed, which consists of two crews of 35 technicians, which are exchanged every two weeks. At all times 35 technicians are required for carrying out maintenance in the wind plant. For the baseline analysis, it is assumed that these technicians are paid based on hourly tariffs for work only. It is assumed that the technicians cost $125 per man-hour. Personnel are considered to work only during daylight periods, except for repairs that require the use of a jack-up vessel, when two shifts of technicians will work 24 h per day. The cost of technicians and length of working day used in the model are listed in Table 25.

Table 25. Cost and availability of technicians and length of working day

Cost and availability technicians					
Variable costs					
Hourly rate technician	125	USD/hr			
Fixed costs					
Yearly salary costs technician		USD			
Season	**Winter**	**Spring**	**Summer**	**Autumn**	**Year**
Nr. of employed technicians	92	92	66	72	70
Total salary cost [USD]	0	0	0	0	0

Length of working day								
Season	**Normal**				**Long**			
	nr. shifts	start	end		nr. shifts	start	end	
Winter	1	7	17	hr	2	0	24	hr
Spring	1	7	19	hr	2	0	24	hr
Summer	1	6	20	hr	2	0	24	hr
Autumn	1	7	19	hr	2	0	24	hr
Year	1	7	19	hr	2	0	24	hr

Wind Plant Breakdown and Failure Rates

A breakdown of the wind turbines was made to assign failure frequencies to the individual components. In addition, the failure rates of certain balance of plant items were considered. Both aspects are discussed in the following subsections.

Wind Turbine

The annual failure rates set for the main systems of the NREL offshore 5-MW baseline wind turbine are given in Table 26. The wind turbine breakdown in main systems is based on the descriptions published for the NREL offshore 5-MW baseline turbine and assumptions made by NREL and ECN (among others, the assumption that the turbine is equipped with an internal crane). The classification for the wind turbine systems of the NREL 5-MW baseline turbine is based on the Reference Designation System for Power Plants (RDS-PP) taxonomy which is based on basic and sector-specific IEC and ISO standards. The classification is made using the guideline for application of RDS-PP, which is published by VGB PowerTech (VGB PowerTech, 2007).

Table 26. Annual failure rates of components for the NREL offshore 5-MW baseline wind turbine

Wind Turbine Component	Annual Failure Frequency main components Value
MDA- Rotor system	0.1307
MDC - Blade adjustment	0.9778
MDK - Drive train	0.2888
MDL - Yaw gearbox	0.5076
MDX - Hydraulic system	0.0536
MDY - Control and protection system turbine	0.8616
MKA - Generator	0.3246
MKY - Control and protection system generator	0.6001
MSA - Generator lead / transmission cables	0.4651
MST - Transformer	0.0795
MUD - Machinery enclosure	0.0138
UMD - Turbine structure / tower	0.1512
XA - Heating, ventilation, air conditioning	0.0140
XM - Crane system	0.0144
XN - Elevator system	0.0055
AB - Lightning protection / grounding	0.0118
MD - Remote Resets	5.0000
Total	**9.5000**

The failure frequencies (failures per year) for each of the wind turbine's components are derived from the results of the Reliawind project, in which the contribution of components to the overall failure rate is given in percentages. The Reliawind project ran from 2008 to March 2011, and we used the published information on reliability in Deliverable 1.3, which is believed to be the latest information available on the reliability of wind turbines (Wilkinson & Hendriks, 2011) (Wilkinson M. , 2010). According to the publications, failure data were collected by an analysis of, among others, 10-minute SCADA data, automated fault-logs, and O&M reports. The data collected met the following conditions:

- Site of at least 15 wind turbines
- Turbines have been running for at least 2 years since commissioning
- Variable speed, pitch regulated wind turbines (represent modern turbines)
- Rated at > 850 kW.

Based on ECN's experience in O&M modeling, the average annual failure rate for a wind turbine lies between 3 and 6 over a lifetime of 20 years. Therefore, a failure frequency of 4.5 is used for this case study. This is similar to an ECN case study performed for a far offshore wind plant in the North Sea, see (Obdam & van der Zee, 2011). The Reliawind reliability figures are used to calculate a breakdown of failure rates for systems that represent the NREL 5-MW wind turbine. In this process, the Reliawind taxonomy used for data collection is converted to the RDS-PP based taxonomy, for which the details are given in Table 27.

In addition to failures that require a visit to the turbines, the effects of remote resets were also modeled by defining the general wind turbine system code "MD- Remote Resets." For the baseline scenario it is assumed that on average each turbine needs to be remotely reset 5 times per year. Thus, the total modeled failure frequency equals 9.5 failures per year.

Table 27. Conversion of taxonomy used for data collection in Reliawind project to RDS-PP taxonomy

System (RDS-PP taxonomy)	Reliawind sub system or assembly (reliawind WT taxonomy)	Reliawind failures
MDA - Rotor system	Blades + Hub + hub cover	0.1307
MDC - Blade adjustment	Pitch system + slip rings + blade bearings	0.9778
MDK - Drive train	Drive train module	0.2888
MDL - Yaw gearbox	Yaw system	0.5076
MDX - Hydraulic system	Hydraulic system	0.0536
MDY - Control and protection system turbine	Control & comm system + nacelle sensors + CMS + auxiliary + wind farm	0.8616
MKA - Generator	Generator assembly	0.3246
MKY - Control and protection system generator	Power cabinet + protection cabinet + frequency converter	0.6001
MSA - Generator lead / transmission cables	LV & MV switchgear + power feeder cables	0.4651
MST - Transformer	Transformer	0.0795
MUD - Machinery enclosure	Nacelle cover + bedplate + lighting points + beacon	0.0138
UMD - Turbine structure / tower	Structural module	0.1512
XA - Heating, ventilation, air conditioning	Cooling system	0.0140
XM - Crane system	Service crane	0.0144
XN - Elevator system	Lift	0.0055
AB - Lightning protection / grounding	Lightning protection + grounding	0.0118
	Total failures	4.5000

Balance of Plant

Failures in the wind plant offshore substation, foundation and scour protection, and cables (between wind turbines and offshore substation) were also taken into account. However, because very little information was available for these figures, ECN made some best estimates (Obdam & van der Zee, 2011). The resulting numbers are shown in Table 28. The wind plant is assumed to be connected to the grid via an onshore substation, which is subsequently connected to a single offshore substation.

Table 28. Annual failure rates of components for the considered BOP items

BOP Component	Annual Failure Frequency main components Value
Transformer	0.5000
Foundation / Scour protect	3.0000
Cables within wind farm	0.0500

Maintenance Categories and Fault Type Classes

In the following subsections it is discussed in detail how the different Maintenance Categories and fault Type Classes for both wind turbine and balance of plant failures were modeled in the ECN O&M Tool. More information on the maintenance categories is presented in Appendix E.

Wind Turbine

For this analysis, 6 Maintenance Categories (MC) were identified. Each MC is split up into one or more Fault Type Classes (FTC). The modeled MCs and FTCs are shown in Table 29.

Table 29. Maintenance Categories and Fault Type Classes for wind turbine failures

Maintenance categories		Fault type class classification Add Remov	
Description	**Nr**	**Description**	**Nr.**
Remote reset (only downtime, no visit)	1	no crew, Repair = 2 hr, no costs	1
Inspection and small repair inside	2	small crew, Repair = 4 hr, consumables	2
Inspection and small repair outside	3	small crew, Repair = 8 hr, consumables	3
Replacement small parts (< 2 MT) internal crane	4	small crew, Repair = 8 hr, low costs	4
	4	small crew, Repair = 16 hr, low costs	5
	4	large crew, Repair = 16 hr, medium costs	6
	4	large crew, Repair = 24 hr, medium costs	7
	4	large crew, Repair = 24 hr, high costs	8
Preventive replacement small parts (< 2 MT) internal crane	5	small crew, Repair = 8 hr, low costs	9
	5	large crew, Repair = 16 hr, medium costs	10
Replacement large parts (< 100 MT) large external crane	6	large crew, Repair = 24 hr, medium/high costs	11
	6	large crew, Repair = 24 hr, high costs	12
	6	large crew, Repair = 40 hr, medium/high costs	13
	6	large crew, Repair = 40 hr, very high costs	14

The material costs, crew size, repair time and logistic time shown in Table 30 are all based on experience from ECN with O&M modeling. The FTCs were developed largely based on our existing Demo K13 baseline model for the North Sea, which is supplied with the commercial O&M Tool software (Obdam & van der Zee, 2011). For the Demo K13 model, the FTCs are developed based on an analysis of the contribution to overall downtime and engineering judgment to classify small, medium, and large repair actions. These analyses were performed in the past by ECN together with a turbine manufacturer. The costs for spare parts are quantified using a breakdown that shows the contribution of different component costs to the total investment costs of a modern geared wind turbine. Details for this cost breakdown are given in (Krohn, Morthorst, & Awerbuch, 2009).

It is assumed that small parts (up to 2000 kg) are kept in stock at warehouse facilities at the harbor, and therefore the logistic time for spare parts for MC1 to MC4 was set to zero. MC5 represents preventive replacement of small components; the turbine is assumed to be shut down only when maintenance is being performed. Therefore, the FTCs for MC5 are flagged to be the condition-based maintenance (CBM) type.

Table 30. Fault Type Classes for wind turbine failures

Fault type class classification Add Remove		Type 0 = corr 1 = cbm	Material Costs [% of Investm.]		Crew Size (Labour Costs)	Repair Time [hrs]	Logistic Time Spare Parts [hrs]
Description	Nr.	mean value	mean value	[USD]	mean value	mean value	mean value
no crew, Repair = 2 hr, no costs	1	0	0.00%	0	0	2	0
small crew, Repair = 4 hr, consumables	2	0	0.010%	900	3	4	0
small crew, Repair = 8 hr, consumables	3	0	0.010%	900	3	8	0
small crew, Repair = 8 hr, low costs	4	0	0.100%	9,000	3	8	0
small crew, Repair = 16 hr, low costs	5	0	0.100%	9,000	3	16	0
large crew, Repair = 16 hr, medium costs	6	0	1.000%	90,000	4	16	0
large crew, Repair = 24 hr, medium costs	7	0	1.000%	90,000	4	24	0
large crew, Repair = 24 hr, high costs	8	0	5.000%	450,000	4	24	0
small crew, Repair = 8 hr, low costs	9	1	0.100%	9,000	3	8	0
large crew, Repair = 16 hr, medium costs	10	1	1.000%	90,000	4	16	0
large crew, Repair = 24 hr, medium/high costs	11	0	2.000%	180,000	6	24	168
large crew, Repair = 24 hr, high costs	12	0	3.000%	270,000	6	24	336
large crew, Repair = 40 hr, medium/high costs	13	0	2.000%	180,000	6	40	336
large crew, Repair = 40 hr, very high costs	14	0	10.000%	900,000	6	40	336

Fault type class classification Add Remove		Type 0 = corr 1 = cbm	Time to Organise [hrs]	Length working day 0 = normal 1 = long	Repair splittable 0 = no 1 = yes
Description	Nr.	mean value	mean value	mean value	mean value
no crew, Repair = 2 hr, no costs	1	0	0	1	1
small crew, Repair = 4 hr, consumables	2	0	6	0	1
small crew, Repair = 8 hr, consumables	3	0	6	0	1
small crew, Repair = 8 hr, low costs	4	0	12	0	0
small crew, Repair = 16 hr, low costs	5	0	12	0	0
large crew, Repair = 16 hr, medium costs	6	0	12	0	0
large crew, Repair = 24 hr, medium costs	7	0	12	0	0
large crew, Repair = 24 hr, high costs	8	0	12	0	0
small crew, Repair = 8 hr, low costs	9	1	12	0	0
large crew, Repair = 16 hr, medium costs	10	1	12	0	0
large crew, Repair = 24 hr, medium/high costs	11	0	24	1	0
large crew, Repair = 24 hr, high costs	12	0	24	1	0
large crew, Repair = 40 hr, medium/high costs	13	0	24	1	0
large crew, Repair = 40 hr, very high costs	14	0	24	1	0

It is also taken into account that before a replacement is carried out, first one or more inspections are performed. For the baseline scenario, it is assumed that before small (MC4) and large (MC6) replacements, on average respectively 1 and 2 inspections are carried out. These inspections can be characterized as small repairs (MC2). The assignment of additional inspections is illustrated in Table 31 for two components.

Table 31. Assignment of additional inspections for wind turbine failures

Wind Turbine Component Add Remove	Annual Failure Frequency main components Value	Mainte-nance Category	Probability of occurrence Maint. Cat	Annual Failure Frequency maintenance categories		Number of additional inspections	FTC
MDA- Rotor system	0.1307	2	52.5%	0.134	0.069		2
MDC - Blade adjustment	0.9778	2	65%	0.831	0.636		2
		4	10%	0.098	0.098	1	6
		5	20%	0.196	0.196		9
		6	5%	0.049	0.049	2	11
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MDK - Drive train	0.2888	2	45%	0.318	0.130		2
MDL - Yaw gearbox	0.5076	2	45%	0.330	0.228		2
		5	45%	0.228	0.228		10
		6	10%	0.051	0.051	2	13
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		

For the components MDC – Blade adjustment, MDL – Yaw gearbox, and XN – Elevator system, it was assumed that part of the maintenance can be carried out in a preventive manner(e.g., for the replacement of certain small components such as pitch motors/batteries, yaw drives, and elevator components). The turbine only has to be shut down during the actual replacement, and therefore no time-to-organize, logistics, weather, and travel downtime have to be considered. These preventive replacements are categorized as MC5. The full assignment of all Maintenance Categories and Fault Type Classes to the different wind turbine components is listed in Table 32.

Table 32. Wind turbine MCs and FTCs

Wind Turbine Component Add Remove	Annual Failure Frequency main components Value	Mainte-nance Category	Probability of occurrence Maint. Cat	Annual Failure Frequency maintenance categories		Number of additional inspections	FTC
MDA- Rotor system	0.1307	2	52.5%	0.134	0.069		2
		3	5.0%	0.007	0.007		3
		4	15.0%	0.020	0.020	1	4
		4	20.0%	0.026	0.026	1	6
		6	5.0%	0.007	0.007	2	13
		6	2.5%	0.003	0.003	2	14
				0.000	0.000		
				0.000	0.000		
MDC - Blade adjustment	0.9778	2	65%	0.831	0.636		2
		4	10%	0.098	0.098	1	6
		5	20%	0.196	0.196		9
		6	5%	0.049	0.049	2	11
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MDK - Drive train	0.2888	2	45%	0.318	0.130		2
		4	45%	0.130	0.130	1	6
		6	10%	0.029	0.029	2	14
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MDL - Yaw gearbox	0.5076	2	45%	0.330	0.228		2
		5	45%	0.228	0.228		10
		6	10%	0.051	0.051	2	13
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MDX - Hydraulic system	0.0536	2	60%	0.054	0.032		2
		4	40%	0.021	0.021	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MDY - Control and protection system turbine	0.8616	2	55%	0.862	0.474		2
		4	45%	0.388	0.388	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MKA - Generator	0.3246	2	45%	0.357	0.146		2
		4	45%	0.146	0.146	1	6
		6	10%	0.032	0.032	2	12
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MKY - Control and protection system generator	0.6001	2	45%	0.600	0.270		2
		4	45%	0.270	0.270	1	5
		4	10%	0.060	0.060	1	8
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MSA - Generator lead / transmission cables	0.4651	2	55%	0.465	0.256		2
		4	45%	0.209	0.209	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		

MST - Transformer	0.0795	2	45%	0.079	0.036		2
		4	45%	0.036	0.036	1	5
		4	10%	0.008	0.008	1	8
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MUD - Machinery enclosure	0.0138	2	40%	0.014	0.006		2
		4	60%	0.008	0.008	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
UMD - Turbine structure / tower	0.1512	2	55%	0.159	0.083		2
		4	30%	0.045	0.045	1	4
		4	10%	0.015	0.015	1	7
		6	5%	0.008	0.008	2	14
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
XA - Heating, ventilation, air conditioning	0.0140	2	50%	0.014	0.007		2
		4	50%	0.007	0.007	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
XM - Crane system	0.0144	2	50%	0.014	0.007		2
		4	50%	0.007	0.007	1	4
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
XN - Elevator system	0.0055	5	100%	0.005	0.005		9
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
AB - Lightning protection / grounding	0.0118	2	100%	0.012	0.012		2
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
MD - Remote Resets	5.0000	1	100%	5.000	5.000		1
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
				0.000	0.000		
Total	9.5000	**1**		**5.0000**	**5.0000**		
		2		**4.2424**	**2.3909**		
		3		**0.0065**	**0.0065**		
		4		**1.4948**	**1.4948**		
		5		**0.4294**	**0.4294**		
		6		**0.1783**	**0.1783**		
		7		**0.0000**	**0.0000**		
		8		**0.0000**	**0.0000**		
				11.3514	9.5000		

Additional inspections	
Inspection MC	2

Balance of Plant

For BOP failures, four maintenance categories are identified. Again, each MC is split up in one or more Fault Type Classes. The modeled MCs and FTCs for BOP failures are shown in Table 33, Table 34, and Table 35.

Table 33. Maintenance Categories and Fault Type Classes for BOP failures

Maintenance categories		Fault type class classification Add Remov	
Description	Nr	Description	Nr.
Small transformer repair	1	small crew, Repair = 8 hr, low costs	1
Large transformer repair	2	medium crew, Repair = 48 hr, high costs	2
Small foundation / scour protection repair	3	diving crew, Repair = 8 hr, low costs	3
Cable replacement	4	no crew, Repair = 32 hr, high costs	4

The material costs, repair times, crew sizes and logistic times for the different BOP repairs and replacements shown in Table 33 are ECN's best estimates and are taken from (Obdam & van der Zee, 2011). As can be seen, no crew size is defined for both the small foundation/scour protection repair and cable replacement. For these maintenance activities, labor costs for divers and specialist technicians are assumed to be included in the costs for the vessels.

Table 34. Fault Type Classes for BOP failures (1)

Fault type class classification Add Remove		Material Costs [USD]	Crew Size [-]	Repair Time [hrs]	Logistic Time Spare Parts [hrs]
Description	Nr.	mean value	mean value	mean value	mean value
small crew, Repair = 8 hr, low costs	1	6,000	3	8	0
medium crew, Repair = 48 hr, high costs	2	300,000	4	48	1440
diving crew, Repair = 8 hr, low costs	3	6,000	0	8	48
no crew, Repair = 32 hr, high costs	4	450,000	0	32	240

Similar to wind turbine failures, a time-to-organize is also modeled for BOP failures. For the small repairs, a period of 6 h is considered, whereas for the large transformer repairs, a period of 12 h is considered, and for cable replacements one period of 24 h is taken into account. Furthermore, for all BOP failures it is assumed that the repair activities can only be carried out during daylight conditions (normal working day). Additionally, it is assumed that all BOP repairs and replacements can be carried out over multiple nonadjacent days (splittable).

For the wind plant, it is assumed that all turbines are connected to an onshore substation via a single offshore transformer station. Therefore, a transformer station failure is assumed to affect 100% of the wind turbines in the wind plant. Furthermore, it is assumed that during a small repair on the foundation or scour protection no turbines have to be shut down. Finally, the assumption is made that in case of a cable failure, on average 13% (approximately 1/8) of the wind plant has to be shut down.

Table 35. Fault Type Classes for BOP failures (2)

Fault type class classification (Add / Remove)		Time to Organise [hrs]	Length working day 0 = normal 1 = long	Repair splittable 0 = no 1 = yes	Percentage wind farm shut down [%]
Description	Nr.	mean value	mean value	mean value	
small crew, Repair = 8 hr, low costs	1	6	0	1	100%
medium crew, Repair = 48 hr, high costs	2	12	0	1	100%
diving crew, Repair = 8 hr, low costs	3	6	0	1	0%
no crew, Repair = 32 hr, high costs	4	24	0	1	13%

The full assignment of MCs and FTCs for BOP components is shown in Table 36.

Table 36. Assignment of MCs and FTCs for BOP components

BOP Component (Add / Remove)	Annual Failure Frequency main components Value	Mainte-nance Category	Probability of occurrence Maint. Cat	Annual Failure Frequency maintenance categories		FTC
Transformer	0.5000	1	90%	0.450	0.450	1
		2	10%	0.050	0.050	2
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
Foundation / Scour protection	3.0000	3	100%	3.000	3.000	3
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
Cables within wind farm	0.0500	4	100%	0.050	0.050	4
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
				0.000	0.000	
Total	**3.5500**	**1**		**0.4500**	**0.4500**	
		2		**0.0500**	**0.0500**	
		3		**3.0000**	**3.0000**	
		4		**0.0500**	**0.0500**	
		5		**0.0000**	**0.0000**	
		6		**0.0000**	**0.0000**	
		7		**0.0000**	**0.0000**	
		8		**0.0000**	**0.0000**	
				3.5500	**3.5500**	

Repair Strategy: Transportation and Lifting Equipment

A baseline O&M scenario is worked out in which the following devices for transportation and hoisting are foreseen:

- Workboat access vessel (transferring technicians and transporting small components)
- Jack-up vessel (transporting and hoisting large components)
- Cable-laying vessel (replacing cables)
- Diving support vessel (for underwater inspections and repairs)
- Turbine cranes capable of hoisting small components to and from the workboats. (internal crane at the nacelle and davit crane on the turbine platform).

The relevant model input data for these vessels are given in Appendix D. The figures used are partly based on previous experience from ECN, combined with available data sheets from the manufacturers of this equipment, and some engineering judgment. Using the information from chapter 4, the equipment, including costs and weather limits, are modeled in the O&M Tool as depicted in Table 37.

Table 37. Definition of equipment for baseline O&M cost model

EQUIPMENT

U.S. baseline IO&M case study

Nr of equipment	Description of equipment	Weather window (normal day)	Hs	Vw	0	0	Weather window (long day)	Hs	Vw	0	0
			(For information only)					(For information only)			
1	Workboat	3	0.90	12.0	0.00	0.0	4	0.90	12.0	0.00	0.0
2	Jack-up barge (100 MT)	1	2.50	10.0	0.00	0.0	2	2.50	10.0	0.00	0.0
3	Cable layer	5	1.00	25.0	0.00	0.0		0.00	0.0	0.00	0.0
4	Diving support vessel	6	2.00	25.0	0.00	0.0		0.00	0.0	0.00	0.0
5	Turbine crane	7	0.90	10.0	0.00	0.0		0.00	0.0	0.00	0.0
6	Blade inspection	8	0.90	8.0	0.00	0.0		0.00	0.0	0.00	0.0

Season: Year

Nr of equipment	Description of equipment	Avail-ability (nr. of equipment)	T logistic equip.	T travel (+access) one way		Fixed costs per available equipment [USD/year]	Cost equipment for MOB/DEMOB [USD/mission]	Variable cost equipment (waiting and repair) [USD/unit]			Additional costs equipment during traveling [USD/trip]
		nr	hr	hr	Freq. 0: day 1: mission	USD/year	USD/ mission	USD/ unit	unit 0: hr 1: day	Weighing factor Costs T_wait	USD/trip
1	Workboat		0	2.6	0			2,000	1	0.75	500
2	Jack-up barge (100 MT)		720		1		440,000	155,000	1	0.75	310,000
3	Cable layer		720		1		560,000	190,000	1	0.75	190,000
4	Diving support vessel		360		1		190,000	95,000	1	0.75	95,000
5	Turbine crane										
6	Blade inspection										

The following main assumptions are made in modeling of the defined equipment:

- No travel times are modeled for the jack-up barge, cable-laying vessel, and diving support vessel. Naturally these vessels need some time to travel to the wind plant, but more relaxed weather restrictions apply as these types of large vessels are in transit. If a travel time would be modeled, the waiting time for this equipment would be overestimated.

- For the turbine crane and blade inspection equipment, no logistic time, travel time, and costs are specified. However, only the appropriate weather window is selected to account for the possible waiting time associated with using the equipment. For both the turbine crane and blade inspection equipment, a maximum significant wave height of 0.9 m is modeled, because of the fact that during operations with this equipment it should be possible to transfer technicians to the workboat at all times.
- For the workboat and jack-up barge, a weather window for both a "normal" and a "long" working day is selected. For the baseline scenario, the workboat is applied in both normal and long working days. The jack-up is only applied during long working days, but in a sensitivity study the application of the jack-up barge during normal working days may also be investigated.
- All vessels are assumed to be leased when required for maintenance. For the jack-up barge, cable-laying vessel, and diving support vessel, a mobilization time is modeled to reflect limited availability on the market for such large vessels. The workboats are assumed to be readily available upon request.
- The fuel cost for the workboat is given as the costs per trip. A round trip will take approximately 5 h (2 one-way trips of 2.6 h), with an assumed fuel cost of $100/h this leads to a modeled fuel cost of $500 per trip.

For the jack-up barge, different logistic times and costs are modeled for winter and summer (see Appendix D). The variations per season are listed in Table 38. The logistics time and costs for spring and autumn are assumed equal to values used to model the yearly average. Table 39 shows which equipment will be deployed for each defined FTC for both the wind turbines and BOP. The numbers in the block Repair Strategy of this table correspond with the numbers in Table 37 where the devices are specified in detail.

Table 38. Definition of logistic times and costs for jack-up during winter and summer seasons

	Season: Winter												
Description of equipment	**Availability**	**T logistic equip.**		**Fixed costs per available equipment [USD/season]**		**Cost equipment for MOB/DEMOB [USD/mission]**		**Variable cost equipment (waiting and repair) [USD/unit]**				**Additional costs equipment during traveling [USD/trip]**	
	nr	hr		USD/ season		USD/ mission		USD/ unit		unit 0: hr 1: day	Weighing factor Costs T_wait	USD/trip	
Jack-up barge (100 MT)	0	480		0		315,000		125,000		1	0.75	250,000	

	Season: Summer												
Description of equipment	**Availability**	**T logistic equip.**		**Fixed costs per available equipment [USD/season]**		**Cost equipment for MOB/DEMOB [USD/mission]**		**Variable cost equipment (waiting and repair) [USD/unit]**				**Additional costs equipment during traveling [USD/trip]**	
	nr	hr		USD/ season		USD/ mission		USD/ unit		unit 0: hr 1: day	Weighing factor Costs T_wait	USD/trip	
Jack-up barge (100 MT)	0	960		0		560,000		190,000		1	0.75	380,000	

Table 39. Equipment applied per Maintenance Category for wind turbine (top) and BOP (bottom)

Distribution of Fault Type Classes and Cost Breakdown for Wind Turbine				*Season: Year*								
Maintenance categories		**Fault type class classification** Add Remove		**Repair strategy** Usage of devices				**Time [hrs] equipment is used during repair** If 0 equal to repair time				**Effective length working day [hrs]**
Description	**Nr**	**Description**	**Nr.**	*Access equipment*	*2nd device*	*3rd device*	*4th device*	*Access equipment*	*2nd device*	*3rd device*	*4th device*	
Remote reset (only downtime, no visit)	1	no crew, Repair = 2 hr, no costs	1									24
Inspection and small repair inside	2	small crew, Repair = 4 hr, consumables	2	1								6.8
Inspection and small repair outside	3	small crew, Repair = 8 hr, consumables	3	1	5	6			2			6.8
Replacement small parts (< 2 MT) internal crane	4	small crew, Repair = 8 hr, low costs	4	1	5				2			6.8
	4	small crew, Repair = 16 hr, low costs	5	1	5				4			6.8
	4	large crew, Repair = 16 hr, medium costs	6	1	5				4			6.8
	4	large crew, Repair = 24 hr, medium costs	7	1	5				6			6.8
	4	large crew, Repair = 24 hr, high costs	8	1	5				6			6.8
Preventive replacement small parts (< 2 MT) internal crane	5	small crew, Repair = 8 hr, low costs	9	1	5				2			6.8
	5	large crew, Repair = 16 hr, medium costs	10	1	5				4			6.8
Replacement large parts (< 100 MT) large external crane	6	large crew, Repair = 24 hr, medium/high costs	11	1	2				12			13.6
	6	large crew, Repair = 24 hr, high costs	12	1	2				12			13.6
	6	large crew, Repair = 40 hr, medium/high costs	13	1	2				20			13.6
	6	large crew, Repair = 40 hr, very high costs	14	1	2				20			13.6

Distribution of Fault Type Classes and Cost Breakdown for Balance of Plant				*Season: Year*								
Maintenance categories		**Fault type class classification** Add Remove		**Repair strategy** Usage of devices				**Time [hrs] equipment is used during repair** If 0 equal to repair time				**Effective length working day [hrs]**
Description	**Nr**	**Description**	**Nr.**	*Access equipment*	*2nd device*	*3rd device*	*4th device*	*Access equipment*	*2nd device*	*3rd device*	*4th device*	
Small transformer repair	1	small crew, Repair = 8 hr, low costs	1	1								6.8
Large transformer repair	2	medium crew, Repair = 48 hr, high costs	2	1								6.8
Small foundation / scour protection repair	3	diving crew, Repair = 8 hr, low costs	3	4								12
Cable replacement	4	no crew, Repair = 32 hr, high costs	4	3								12

Preventive Maintenance and Fixed Yearly Costs

For the baseline scenario it is assumed that all turbines in the wind plant will be maintained once per year (so 19 times during the 20-year lifetime of the wind plant), with 3 technicians during 24 h. In addition to this, every five years (3 times during the 20-year lifetime of the wind plant) a larger preventive maintenance campaign is carried out. This campaign requires a crew of 6 technicians during 48 h. It is also assumed that in the years a large preventive campaign is carried out that no regular preventive maintenance is performed. Therefore, during the 20-year lifetime the following was assumed:

- 16 times regular preventive maintenance
- 3 times large preventive maintenance.

It is assumed that for both maintenance campaigns the workboats can be used and that work can only be performed during daylight hours (normal working day). Furthermore, the required material costs are a best estimate, based on ECN's experience in O&M modeling.

It is also assumed that all balance of plant preventive maintenance is carried out from a diving support vessel (i.e., regular underwater inspections). Because this vessel can stay within the wind plant for the duration of the maintenance, travel time does not need to be modeled. The crew costs are included in the rate for the diving support vessel. It is estimated that 160 h of BOP preventive maintenance is carried out every year throughout the 20 years of assumed lifetime of the wind plant. The input sheet for preventive maintenance is depicted in Table 40.

In this study, only costs directly related to corrective and preventive maintenance have been taken into account. Other costs, for instance, costs for a 24-h control room or insurance costs, are outside the scope of this study.

Table 40. Input parameters preventive maintenance wind turbine and BOP structures

Preventive maintenance per wind turbine or BOP item										
Description	***Regular WT preventive maintenance***					***Large WT preventive maintenance***				
Type of preventive maintenance (0 = WT; 1 = BOP)		0	-				0	-		
Percentage wind farm shut down (only for BOP) [%]										
Number of occurances during lifetime of 20 years		16	-				3	-		
Duration of maintenance		24	hrs				48	hrs		
Crew size		3	-				6	-		
Mat. Costs		12,500	USD				37,500	USD		
Type of equipment		1	Workboat				1	Workboat		
Travel time to or from the wind farm (one-way) [hr]		2.1	hrs				2.1	hrs		
Length working day (0 = normal; 1 = long)		0	-				0	-		
Distribution over seasons		winter	spring	summer	autumn		winter	spring	summer	autumn
		0%	35%	55%	10%		0%	35%	55%	10%

Preventive maintenance per wind turbine or BOP item					
Description	***Regular BOP preventive maintenance***				
Type of preventive maintenance (0 = WT; 1 = BOP)		1	-		
Percentage wind farm shut down (only for BOP) [%]		0%			
Number of occurances during lifetime of 20 years		19	-		
Duration of maintenance		160	hrs		
Crew size		0	-		
Mat. Costs		12,500	USD		
Type of equipment		4	Diving support vessel		
Travel time to or from the wind farm (one-way) [hr]		0	hrs		
Length working day (0 = normal; 1 = long)		0	-		
Distribution over seasons		winter	spring	summer	autumn
		0%	35%	55%	10%

Appendix D. Vessel Data

For the baseline configuration, it has been decided that the following methods and equipment are the most likely option for the transfer of equipment and personnel and for hoisting components:

- Workboat access vessel (for transferring technicians and transporting small components)
- Jack-up vessel (for transporting and hoisting large components)
- Cable-laying vessel (for replacing cables)
- Diving support vessel (for underwater inspections and repairs)
- Turbine cranes capable of hoisting small components to and from the workboats (specifically, internal crane at the nacelle and davit crane on the turbine platform).

Workboat Access Vessel

For the transfer of personnel and small spare parts, a workboat vessel type is used. The workboats considered in this study are relatively fast and can transport up to 12 persons. The specifications used for the cost modeling are given in Table 41.

Table 41. Specifications of the workboat access vessel

Workboat - 12 persons		
Specification	**Value**	**Remarks**
H_s max at transfer	0.9 m	Average wave height limits taken from (Douglas-Westwood, 2012)
V max at transfer	12 m/s	This limit refers to the maximum allowed wind speed for personnel working in the nacelle (Obdam & van der Zee, 2011)
Travel time to turbine (or speed)	2.6 h	*Engineering judgment* (Obdam & van der Zee, 2011) Travel time to wind plant 2.3 h (86km/20 kts) + Time for access to turbine 0.3 h (estimate) + The total travel time is estimated at 2.6 h (avg).
Maximum crew size	12	*Assumption*
Mobilization time	0 h	*Assumption, depends on market conditions*
Availability	-	The workboats are chartered when required.
Maximum weight of load	2000 kg	*Assumption* Deck crane with 2 ton safe work load
Day rate	2k Dollar/day (75% waiting)	*Estimate* Based on ECN's discussions with vessel operators
Mob + demob costs	0	No MOB/DEMOB costs applicable
Fuel costs	Approx. 100 Dollars/h	*Engineering judgment* Based on average consumption at cruise speed and while idling of 100 L/h (Diesel price $4.00/gallon)

Jack-Up Vessel

The transportation and hoisting of large components, such as that during installation, will be done with a jack-up vessel, because of its ability to lift itself out of the water. A stable platform is created, from which a large crane can be operated. The specifications used for the cost modeling are given in Table 42.

Table 42. Specifications of the jack-up vessel with crane

Jack-up vessel		
Specification	**Value**	**Remarks**
H_s max	2.5 m	(Douglas-Westwood, 2012)
V max	10 m/s	Relevant for hoisting (Obdam & van der Zee, 2011).
Travel time (one way)	-	The travel time is at least one day. However, during this period weather conditions are not relevant and therefore no travel time needs to be modeled.
Mobilization time	720 h (year, spring, autumn) 480 h (winter) 960 h (summer)	*Estimate, depends on market conditions* Based on values in (Obdam & van der Zee, 2011)
Availability	Limited	Chartered when required.
Maximum height of crane	100 m	
Maximum weight of load	> 100 MT	
Day rate	155k Dollar (year, spring, autumn) 125k Dollar (winter) 190k Dollar (summer) (75% during waiting in harbor)	*Estimate* Based on values in (Obdam & van der Zee, 2011).
MOB + DEMOB costs	440k Dollar (year, spring, autumn) 315k Dollar (winter) 560k Dollar (summer)	*Estimate* Based on values in (Obdam & van der Zee, 2011).
Cost during travel	310k Dollar (year, spring, autumn) 250k Dollar (winter) 380k Dollar (summer)	*Assumption:* two days of travel are required → travel costs equal two times the day rate

Cable Layer

For the (re)placement of cables within the wind plant, a cable-layer vessel is used. The vessel has the necessary equipment to dig up and remove the failed cable, lay the new cable, and bury it. The cable layer is equipped with a Remotely Operated Vehicle (ROV).The vessel stays inside the wind plant throughout the repair action. The vessel has all necessary equipment and technicians on board to lay a new cable in the wind plant. The specifications used for the cost modeling are given in Table 43.

Table 43. Specifications of the cable-laying vessel

Cable laying vessel		
Specification	**Value**	**Remarks**
H_s max during cable laying	1.0 m	Source: Van Oord DOWEC study (Van Oord ACZ, 2001)
V max during cable laying	Not relevant	Modeled as 25 m/s
Travel time to turbine	3.5 h	*Engineering judgment* Based on a transit speed of 14 kts (Douglas-Westwood, 2012)However, during this periods weather conditions are not relevant and therefore no travel time needs to be modeled.
Mobilization time	720 h	*Estimate, depends on market conditions*
Availability	Limited	Chartered when required.
Maximum weight of load	1000 tons	
Day rate	190k Dollar (75% during waiting in harbor)	*Estimate* Based on values given (Obdam & van der Zee, 2011)
MOB + DEMOB costs	560k Dollar	*Estimate* Based on values given (Obdam & van der Zee, 2011)
Cost during travel	190k Dollar	Based on the assumption that in total one day of travel is needed → travel costs equal the day rate

Diving Support Vessel

For inspection and repair under water, for instance of foundations and scour protection, a diving support vessel is required. It is assumed that a crew of divers is included in the day rate. It is assumed that the diving support vessel is equipped with a Remotely Operated Vehicle (ROV). During longer operations, the diving crew can stay on the vessel, which remains inside the wind plant. The specifications used for the cost modeling are given in Table 44.

Table 44. Specifications of the diving support vessel

Diving support vessel		
Specification	**Value**	**Remarks**
H_s max during operation	2.0 m	
V max during operation	Not relevant	Modeled as 25 m/s
Travel time to turbine	3 h	Based on a transit speed of 16 knots. However, during this periods weather conditions are not relevant and therefore no travel time needs to be modeled.
Mobilization time	360 h	*Estimate, depends on market conditions*
Availability	Limited	Chartered when required.
Maximum weight of load	Not relevant	
Day rate	95k Dollar (75% during waiting in harbor)	*Estimate* Based on values given (Obdam & van der Zee, 2011)
MOB + DEMOB costs	190k Dollar	*Estimate* Based on values given (Obdam & van der Zee, 2011)
Cost during travel	95k Dollar	Based on the assumption that in total one day of travel is needed → travel costs equal the day rate
Fixed annual costs	-	Not applicable

Turbine Crane

To hoist small components up to 2000 kg up to the nacelle for repairs and small replacements, the davit and nacelle cranes available on the wind turbine are used. The davit crane on the platform is used to hoist small components from a vessel to and from the platform, after which the nacelle crane is used to lift those all the way up to the nacelle. The nacelle crane can lift small components from the platform of the wind turbine up to the nacelle at moderate wind speeds. The specifications used for the cost modeling are given in Table 45.

Table 45. Specifications of the nacelle crane

Specifications of the nacelle crane			
Specification	**Value**		**Remarks**
H_s max at transfer	Hoisting	0.9 m	Assumed equal to the workboat's access limits
V max at transfer	Hoisting	10 m/s	*Estimate*
Availability	One crane available for each wind turbine.		100 Cranes in total
Maximum weight of load	2000 kg		*Estimate*
Costs	-		Not applicable The crane will receive preventive maintenance at regular intervals.

Appendix E. Maintenance Categories and Repair Strategies

Six different Maintenance Categories for the wind turbines are identified for the baseline and advanced strategies. In addition, four Maintenance Categories regarding BOP are defined. All 10 MCs are discussed in the following subsection.

Wind Turbine

In Table 46, the six identified Maintenance Categories for the wind turbine are listed.

Table 46. Maintenance Categories for the turbine

Cat. 1:	Remote resets, no access, only downtime
Cat. 2:	Inspection and small repair inside, only personnel and tools, repair time 2 to 6 h (e.g., replacement of generator fuses)
Cat. 3:	Inspection and small repair outside, only personnel and tools, repair time 6 to 10 h (e.g., cleaning of blades)
Cat. 4:	Replacement of small parts (≤ 2000 kg), internal crane, hoisting outside, repair time typically 8 to 24 h (e.g., replacement of pitch motor)
Cat. 5:	Preventive replacement of small parts (≤ 2000 kg), internal crane, hoisting outside, repair time typically 8 to 24 h (e.g., replacement of pitch batteries)
Cat. 6:	Replacement of large parts (≥ 2000 kg), external crane on jack-up vessel needed, (e.g., replacement blade, pitch bearing, etc.), repair time typically 24 to 40 h

Below, for each MC, the typical maintenance actions are worked out in more detail. As stated already in the introduction, all data should be considered best estimates.

Cat. 1: Remote Resets

The wind turbines can shut down because of certain warnings or errors.

The typical actions for a remote reset look like this:

1. The turbine is shut down because of a warning.
2. The 24-h monitoring team investigates the cause of the error (~2 h).
3. If the warning is found to be not serious, the turbine is restarted.

The reset can be carried out in 2 h. Transportation of personnel and access to the turbine is not necessary, because all actions are carried out remotely.

Cat. 2: Inspection and Small Repair Inside the Turbine

Three technicians have to be transported to the turbine to carry out the inspection or repair. No additional equipment needs to be transported; only tools that fit into a toolbox.

A typical inspection or repair looks like this:

1. The workboat is launched from the harbor and travels to the faulted wind turbine (~2.3 h).
2. Three (3) technicians are transferred from the workboat to the turbine (~0.3 h).
3. Technicians carry out inspection or repair, the workboat remains within the wind plant (2 to 6 h).
4. Personnel return to the workboat and travel back to the harbor (~2.6 h).

The repair can be carried out in 2 to 6 h. Transportation of personnel and access to the turbine can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. On average, a period of 6 h is required to organize the inspection or repair.

For these inspections or repairs a normal working day (only during daylight) is applicable. Furthermore, these repairs do not have to be carried out in one continuous period with good weather, but can be split over multiple nonadjacent days.

Cat. 3: Inspection and Small Repair Outside the Turbine

This category includes, for instance, cleaning of the blades or inspection of the tower, or repairing the gel coat of the blades. At least two technicians need to be transported to the turbine to carry out an inspection or repair at the outside of the turbine. Transportation of the necessary equipment for lowering personnel from the hub along the blade(s) can be done with the workboat.

A typical inspection looks like this: .

1. The workboat, with hoisting equipment, is launched from the harbor and travels to the faulted wind turbine (~2.3 h).
2. Three (3) technicians with gear for working outside are transferred from the workboat (~ 0.3 h).
3. The equipment will be put on the platform and hoisted with the turbine crane into the nacelle or hub, and the equipment for lowering technicians will be installed (1 h).
4. The technician is hoisted from the hub along blade 1, and blade 1 is inspected.
5. The technician is hoisted into hub.
6. The rotor is rotated through 120 degrees and steps 3 and 4 are repeated.
7. Step 5 is repeated.
8. Personnel return to the workboat and travel back to the harbor (~2.6 h).

The installation of the hoisting equipment and subsequent inspection of all three blades will take approximately 6 to 10 h. Transportation of personnel and access to the turbine can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. Inspection and repair outside the nacelle can be done in conditions up to $V_w = 8$ m/s (derived from communication with technicians). On average, a period of 6 h is required to organize the inspection or repair.

For these inspections or repairs a normal working day (only during daylight) is applicable. Furthermore, these repairs do not have to be carried out in one continuous period with good weather, but can be split over multiple nonadjacent days.

Cat. 4: Replacement of Small Parts (< 2000 kg)

Smaller spare parts like a pitch motor, or parts of a hydraulic system, need to be transported to the turbine, put on the platform, and subsequently hoisted into the nacelle with the help of the internal crane. All smaller spare parts weigh less than 2000 kg.

A typical maintenance action looks like the following:

Inspection

1. The workboat is launched from the harbor and travels to the faulted wind turbine (~2.3 h).
2. Three (3) technicians are transferred from the workboat to the turbine (~ 0.3 h).
3. Technicians carry out inspection, the workboat remains within the wind plant (~ 2 to 6 h).
4. Personnel return to the workboat and travel back to the harbor (~2.6 h).

Replacement

1. A workboat, with 3 to 4 technicians and the spare part, is launched from the harbor and travels to the failed turbine (~2.3 h).
2. The technicians are transferred from the workboat (~ 0.3 h).
3. In case the failed component needs to be replaced, the spare component is hoisted to the platform with the small crane on the lower turbine platform (~1 h).
4. The failed component is dismantled and lowered outside the tower to the turbine platform (2 to 8 h).
5. The spare component is hoisted from the platform into the nacelle using the internal crane (~2 h).
6. The spare component is mounted (2 to 12 h).
7. The failed component is hoisted to the workboat using the small crane on the platform. (~ 1 h)
8. Personnel return to the workboat and travel back to the harbor (~2.6 h).

For the inspection, the criteria for MC2 are valid. For the baseline, it is assumed that on average 1 inspection is performed before the actual replacement is carried out.

The total duration of the repair action will be about 8 to 24 h. Transportation of personnel and access to the turbine can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. Putting spare parts from the workboat on the platform using a Davit crane can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m, hoisting of equipment from the platform to the nacelle with the turbine crane is possible in conditions up to V_w = 10 m/s. Spare parts for this category are kept in stock at the harbor. On average, a period of 12 h is required to organize the repair action.

For these inspections or repairs, a normal working day (only during daylight) is applicable. Furthermore, these repairs do have to be carried out in one continuous period with good weather and cannot be split over multiple nonadjacent days.

Cat. 5: Preventive Replacement of Small Parts (< 2000 kg)

For the baseline scenario, it is assumed that some of the smaller components (e.g., pitch batteries or yaw drives) can be replaced preventively, based on observed degradation (in fact, condition-based maintenance). The advantages of this planned replacement are that the turbine is only shut down during the actual repair and no logistic, organizational, weather, and travel downtimes have to be considered.

The repair procedure for the preventive replacement of small parts is identical to the corrective replacement (MC4), and will therefore not be elaborated here.

Cat. 6: Replacement of Large Parts with Large External Crane on Jack-Up Vessel

To hoist large components, such as the transformer or blades, a large crane on a jack-up vessel is needed. A typical maintenance action may look like the following:

Inspection

1. The workboat is launched from the harbor and travels to the faulted wind turbine (~2.3 h).
2. Three (3) technicians are transferred from the workboat to the turbine (~ 0.3 h).
3. Technicians carry out the inspection, while the workboat remains within the wind plant (~ 2 to 6 h).
4. Personnel return to the workboat and travel back to the harbor (~2.6 h).

Replacement

1. The workboat is launched from the harbor and travels to the faulted wind turbine (~2.3 h). Note that this has to be done every working day until the repair is finished!
2. Technicians are transferred to the turbine with the workboat (~0.3 h). Note that this has to be done every working day until the repair is finished!
3. The failed component is dismounted (4 to 8 h).
4. The spare part is transported from the harbor to the wind plant by the jack-up vessel (8 h from harbor).
5. The jack-up vessel is positioned (1 h).

6. The failed component is removed and let down to the jack-up vessel and the new component is hoisted (6 to 10 h).

7. The spare part is mounted crudely (2 h).

8. Mounting the new part is finished, and the turbine is taken into operation (12 to 20 h, depending on the component).

9. Personnel return to the workboat and travel back to the harbor (~2.6 h).

For the inspection, the criteria for MC2 are valid. For the baseline, it is assumed that on average 2 inspections are performed before the actual replacement is carried out.

The replacement of the failed component will take about 24 to 40 h. Transportation of personnel and access to the turbine can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. During the hoisting activities, the weather conditions should be good, i.e., a wind speed less than 10 m/s (hoisting and working in the open nacelle). During positioning of the jack-up ship, the significant wave height should be less than 2.5 m. Large spare parts are not kept in stock at the harbor and have to be ordered. The average logistic time for the spare parts is 1 to 2 weeks (168 to 336 h). On average, a period of 24 h is required to organize the repair action.

For these inspections or repairs, a long working day (24-h, around the clock) is applicable. Furthermore, these repairs do have to be carried out in one continuous period with good weather and cannot be split over multiple nonadjacent days.

Balance of Plant (BOP)

In addition to the maintenance categories for the wind turbines, four MCs were defined to consider failure of the foundation, transformer station, and cables. In Table 47, the four identified Maintenance Categories for the wind turbine are listed.

Table 47. Maintenance Categories for Balance of Plant

Cat. 1:	Remote resets, no access, only downtime
Cat. 2:	Inspection and small repair inside, only personnel and tools, repair time 2 to 6 h (e.g., replacement of generator fuses)
Cat. 3:	Inspection and small repair outside, only personnel and tools, repair time 6 to 10 h (e.g., cleaning of blades)
Cat. 4:	Replacement of small parts (≤ 2000 kg), internal crane, hoisting outside, repair time typically 8 to 24 h (e.g., replacement of pitch motor)
Cat. 5:	Preventive replacement of small parts (≤ 2000 kg), internal crane, hoisting outside, repair time typically 8 to 24 h (e.g., replacement of pitch batteries)
Cat. 6:	Replacement of large parts (≥ 2000 kg), external crane on jack-up vessel needed, (e.g., replacement blade, pitch bearing, etc.); repair time typically 24 to 40 h

Below, for each MC, the typical maintenance actions are worked out in more detail. As stated already in the introduction, all data should be considered best estimates.

Cat. 1: Small repair in transformer station

Three technicians have to be transported to the transformer station to carry out the repair. No additional equipment needs to be transported—only tools that fit into a toolbox.

A typical inspection or repair looks like this:

1. The workboat is launched from the harbor and travels to the transformer station where the fault occurred (~2.3 h).
2. Three (3) technicians are transferred from the workboat to the transformer station (~0.3 h).
3. Technicians carry out the repair and the workboat remains in the vicinity of the transformer station (4 to 12 h).
4. Personnel return to the workboat and travel back to the harbor (~2.6 h).

The repair can be carried out in 4 to 12 h. Transportation of personnel and access to the transformer station can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. On average a period of 6 h is required to organize the repair action.

For these inspections or repairs, a normal working day (only during daylight) is applicable. Furthermore, these repairs do not have to be carried out in one continuous period with good weather, but can be split over multiple nonadjacent days.

Cat. 2: Large Repair in Transformer Station

Four technicians have to be transported to the transformer station to carry out the repair. Small components required for the repair are brought to the transformer platform by the workboats.

A typical inspection or repair looks like this:

1. The workboat is launched from the harbor and travels to the transformer station where the fault occurred (~2.3 h).
2. The technicians are transferred from the workboat to the transformer station (~0.3 h).
3. The components are hoisted onto the transformer platform using a crane on the platform (2 to 4 h).
4. Technicians carry out the repair (30 to 52 h).
5. Replaced components are hoisted onto the workboat (2 to 4 h).
6. Personnel return to the workboat and travel back to the harbor (~2.6 h).

The repair can be carried out in 36 to 60 h. Transportation of personnel and access to the transformer station can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. Hoisting spare parts from the workboat on the transformer platform using the platform crane can be done in conditions up to V_w = 12 m/s and H_s = 0.9 m. Spare parts for the transformer station are not kept in stock at the harbor and have to be ordered. The logistic time for the spare parts, including delivery at the harbor, is about 2 months. On average, a period of 12 h is required to organize the repair action.

Cat. 3: Small Repair to Foundation or Scour Protection

For repairs that are carried out under water, a diving support vessel with a crew of divers is required.

A typical underwater repair to foundation or scour protection looks like this:

1. The diving support vessel is launched from the harbor and travels to the location where the fault occurred (3 h).
2. The vessel is positioned near the fault and the diving crew enters the water (~0.5 h).
3. The divers carry out the repair (4 to 12 h).
4. The divers return to the diving support vessel and the vessel travels back to the harbor (~3.5 h).

The repair can be carried out in 4 to 12 h. Diving operations can be done in conditions up to H_s = 2.0 m, where wind speed is not relevant. The logistic time of spare parts required for underwater repairs is about 2 days. On average, a period of 6 h is required to organize the repair action.

Cat. 4: Cable Replacement

If the integrity of one of the cables connecting the wind turbines to the transformer station or the transformer station to the onshore station is damaged, it will have to be replaced. This requires a specialized cable-laying vessel.

A typical cable repair action looks like this:

1. The cable-laying vessel picks up the spare parts from the harbor and travels to the location of the faulted cable (3.5 h).
2. Technicians use an ROV to detach the faulted cable (6 to 10 h).
3. The cable-laying vessel is positioned above the broken cable (4 h).
4. The cable-laying vessel hoists the broken cable from the sea surface (2 to 6 h).
5. The cable-laying vessel lays the new cable (6 to 10 h).
6. Technicians use an ROV to attach the new cable to the structures (6 to 10 h).
7. The affected transformer/wind turbines are commissioned and the cable-laying vessel travels back to the harbor (3.5 h).

The repair can be carried out in 24 to 40 h. Cable-laying operations can be done in conditions up to H_s = 1.0 m, where wind speed is not relevant. The logistic time of spare parts required for cable replacements is about 1 to 2 weeks. On average a period of 24 h is required to organize the repair action.

Appendix F. Preferred O&M Detail

Table 48. Summary of downtime and cost of potential preferred O&M strategies

Summary of downtime and costs		*Availability [%]*
Location	U.S. baseline IO&M case study	*Costs [$ct/kWh]*
Type of WT	NREL offshore 5-MW baseline	*Total effort [M $]*

Wind farm	100 turbines		Baseline	Step 1	Step 1 + Variation A	Step 1 + Variation B	Step 1 + Variation C	Step 1 + Variation D1
Annotation				Access vessel Hs = 1.5m	Mother vessel with 0 costs	Jack-up Tlog = 0h with OPEX	Helicopter access	CBM 50% Detection rate
			Total	Total	Total	Total	Total	Total
Downtime per year								
Corrective WT	Logistics	hr	14,327	14,327	14,327	9,942	14,327	12,445
	Waiting	hr	89,269	17,162	7,832	17,162	13,192	15,568
	Travel	hr	1,540	1,540	296	1,540	861	1,496
	Repair	hr	11,031	11,031	7,155	11,031	11,031	11,031
	TOTAL corrective WT	hr	116,167	44,060	29,610	39,675	39,411	40,540
Corrective BOP	Logistics	hr	7,995	7,995	7,995	7,995	7,995	7,995
	Waiting	hr	7,406	1,680	936	1,680	1,680	1,680
	Travel	hr	130	130	25	130	130	130
	Repair	hr	1,853	1,853	902	1,853	1,853	1,853
	TOTAL corrective BOP	hr	17,384	11,658	9,858	11,658	11,658	11,658
Preventive	TOTAL preventive	hr	2,640	2,640	2,640	2,640	2,640	2,640
	TOTAL	hr	**136,192**	**58,358**	**42,108**	**53,973**	**53,709**	**54,838**
Availability		%	84.5%	93.3%	95.2%	93.8%	93.9%	93.7%
Loss of production per year		MWh	326,003	135,733	94,501	126,617	124,717	127,388
Energy production per year		MWh	1,633,521	1,823,791	1,865,022	1,832,907	1,834,807	1,832,136
Revenue losses per year		kUSD	40,750	16,967	11,813	15,827	15,590	15,924
Costs of repair per year								
Material costs								
Corrective WT	TOTAL corrective WT	kUSD	16,684	16,684	16,684	16,684	16,684	16,684
Corrective BOP	TOTAL corrective BOP	kUSD	58	58	58	58	58	58
Preventive	TOTAL preventive	kUSD	1,574	1,574	1,574	1,574	1,574	1,574
	TOTAL	kUSD	**18,317**	**18,317**	**18,317**	**18,317**	**18,317**	**18,317**
Labour costs								
Corrective WT	TOTAL corrective WT	kUSD	4,366	4,366	3,457	4,366	3,857	4,366
Corrective BOP	TOTAL corrective BOP	kUSD	5	5	4	5	5	5
Preventive	TOTAL preventive	kUSD	2,103	2,103	1,911	2,103	2,103	2,103
	TOTAL		**6,474**	**6,474**	**5,372**	**6,474**	**5,965**	**6,474**
Costs equipment								
Corrective WT	MOB/DEMOB	kUSD	4,615	4,615	4,615	0	4,615	4,615
	Waiting	kUSD	5,379	3,967	2,968	1,925	3,853	3,967
	Repair	kUSD	8,432	8,757	7,229	3,245	11,796	8,757
	TOTAL corrective WT	kUSD	18,426	17,339	14,812	5,170	20,264	17,339
Corrective BOP	MOB/DEMOB	kUSD	598	598	598	598	598	598
	Waiting	kUSD	255	254	253	254	254	254
	Repair	kUSD	611	612	611	612	612	612
	TOTAL corrective BOP	kUSD	1,464	1,463	1,463	1,463	1,464	1,463
Preventive	TOTAL preventive		1,487	1,585	1,565	1,585	1,653	1,585
	TOTAL		**21,376**	**20,387**	**17,839**	**8,218**	**23,381**	**20,387**
Corrective WT		kUSD	**39,476**	**38,389**	**34,953**	**26,220**	**40,805**	**38,389**
Corrective BOP		kUSD	**1,527**	**1,527**	**1,525**	**1,527**	**1,527**	**1,527**
Preventive		kUSD	**5,164**	**5,262**	**5,050**	**5,262**	**5,330**	**5,262**
Fixed yearly costs		kUSD	**0**	**0**	**0**	**0**	**0**	**0**
Total costs of repair		kUSD	46,168	45,178	41,528	33,009	47,663	45,178
Total cost per kWh		USD cent/kWh	2.83	2.48	2.23	1.80	2.60	2.47
Total costs of repair per kW installed		USD/kW	92	90	83	66	95	90
Total cost per kW investment			5.1%	5.0%	4.6%	3.7%	5.3%	5.0%
Total effort								
Sum revenue losses & total costs of repair		kUSD	86,918	62,145	53,341	48,836	63,252	61,102
Summary of cost savings	Potential cost reduction vs baseline (step 1 only) and vs step 1 (Variations)	kUSD/year		24,773	8,804	13,308	-1,108	1,043
	Reduction over lifetime = 20 years	kUSD		495,465	176,079	266,164	-22,154	20,861