NREL Offshore Balance-of-System Model

Michael Maness, Benjamin Maples, and Aaron Smith
National Renewable Energy Laboratory

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January 2017

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Nomenclature/List of Acronyms

BOS	balance of system
BOEM	Bureau of Ocean Energy Management
CapEx	capital expenditures
DOE	U.S. Department of Energy
EIS	Environmental Impact Statement
FEED	front-end engineering design
ICC	installed capital cost
kV	kilovolt
ML	main lattice
MPT	main power transformer
MVA	megavolt ampere
MW	megawatt
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
SAP	site assessment plan
SC	stiffened column
SCBS	system cost breakdown structure
SS	semisubmersible
TC	tapered column
TP	transition piece

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1 Introduction

The U.S. Department of Energy (DOE) has investigated the potential for 20% of nationwide electricity demand to be generated from wind by 2030 and, more recently, 35% by 2050 (DOE 2008; 2015a). Achieving this level of wind power generation may require the development and deployment of offshore wind technologies. DOE (2008) has indicated that reaching these 2030 and 2050 scenarios could result in approximately 10% and 20%, respectively, of wind energy generation to come from offshore resources.

By the end of 2013, 6.5 gigawatts (GW) of offshore wind were installed globally (DOE 2015). The first U.S. project, the Block Island Wind Farm off the coast of Rhode Island, has recently begun operations (Deepwater Wind 2016). One of the major reasons that offshore wind development in the United States is lagging behind global trends is the high capital expenditures (CapEx) required. An understanding of the costs and associated drivers of building a commercial-scale offshore wind plant in the United States will inform future research and help U.S. investors feel more confident in offshore wind development. In an effort to explain these costs, the National Renewable Energy Laboratory (NREL) has developed the Offshore Balance-of-System (BOS) model.

Motivation and Model Use Guidelines

The costs associated with an offshore wind power plant include the CapEx of the turbine, the BOS costs, and the operation and maintenance (O&M) costs over the lifetime of the plant. The Offshore BOS Model focuses on BOS costs, which are a primary driver of the offshore wind capital cost and the levelized cost of energy. BOS costs include all costs associated with wind plant installation and commissioning except for turbine CapEx, O&M costs, and financial costs. BOS costs are broken down into six major categories: development, engineering and management, substructure and foundation, electrical infrastructure, assembly and installation, and plant commissioning. Each of these categories is explained in more detail within this document.

BOS costs contribute approximately 70% of the total installed capital costs (ICC) for offshore wind power plants (Maples et al. 2012; Moné et al. 2015). Thus, it is imperative to understand the impact of these costs on project economics as well as potential cost trends for new offshore wind technology developments. The goal of the Offshore BOS Model is to provide public and private entities including researchers, wind power developers, national laboratories, and government agencies, with a tool that can estimate offshore-wind-power-plant BOS costs with a moderate level of detail. This means that there is uncertainty that accompanies each output produced by the model. The model does not contain the level of detail required to make informed project planning and budget decisions. In addition, it was developed to estimate costs of commercial-scale wind power plants. Confidence in the estimated results diminishes as the wind plant nameplate capacity decreases, meaning that for modeling small demonstration-type projects of 30 megawatts (MW) or less, results will likely be uncertain.

NREL aims to achieve an American Association of Cost Engineers class 4 rating for the Offshore BOS Model. Table 1 shows the breakdown of the association's ranking system for cost estimation tools (Dysert 2016). This table provides a clearer representation of the estimation

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capabilities, approximate uncertainty associated with the estimations, and general purpose and recommended use of the model.

Table 1. American Association of Cost Engineers Cost Estimate Classification Matrix (Dysert 2016)

	Primary Characteristic	*Secondary Characteristic*		
Estimate Class	**Maturity Level of Project Definition Deliverables** (Expressed as % of composite definition)	**End Usage** (Typical purpose of estimate)	**Methodology** (Typical estimating method)	**Expected Accuracy Range**
Class 5	0% to 2%	Concept screening	Capacity-factored parametric models, judgment, or analogy	**L:** -20% to -50% **H:** +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment-factored or parametric models	**L:** -15% to -30% **H:** +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semidetailed unit costs with assembly-level items	**L:** -10% to -20% **H:** +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit costs with forced detailed takeoff	**L:** -5% to -15% **H:** +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit costs with detailed takeoff	**L:** -3% to -10% **H:** +3% to +15%
Notes: The state of process technology, availability of applicable reference cost data, and many other factors affect the range markedly. The +/- value represents the typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for a given scope.				

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2 Methodology

The Offshore BOS Model is an empirically based model that was formulated from market research, available industry data, pricing trends, and expert insights garnered from experienced offshore wind power developers and manufacturers. The accumulated set of data derived from the above sources was used to develop a series of submodels relating key plant parameters to costs.

The backbone of the model was developed from work executed under subcontract with DNV GL, formerly GL Garrad Hassan, and described in detail in Elkinton et al. (2012). The scope of work was to assess the offshore wind industry in Europe and to provide data-informed estimates of the costs of developing an offshore wind plant in the United States. Because of the relative immaturity of the United States' offshore wind industry, the data and relationships in this model are based on the knowledge and experience of Europe's offshore wind industry. Cost estimations have been converted from 2010 Euros to 2010 U.S. dollars.

Many of the relationships used to estimate cost, such as installation cost, and technical variables, such as tower mass, were developed using regression analysis. During this process, data were analyzed to determine the sensitivity of the desired outputs to individual input variables. Subsequently, key input variables were used to build relationships to the desired outputs and create a high level of confidence and consistency with industry data. The resulting equations were then vetted through a series of industry reviews and comparisons with other sources of proprietary and public industry data. These equations can be found in Appendix B.

At a high level, the model estimates cost by linking user inputs with the underlying model relationships or functions. Based on the given inputs as well as wind plant specifications and spatial parameters, the model will calculate a series of key technical parameters or intermediate variables, such as substructure mass or export cable length. From there, the intermediate variables are used to calculate costs and installation duration. To calculate costs, a cost factor such as U.S. dollars per unit length is applied to an intermediate variable such as export cable length. The calculation for installation duration is somewhat more involved, as more constraints are applied. For example, the turbine installation duration is constrained by vessel type and operational limits, turbine size, logistical distances, and number of turbines. Once the installation duration is calculated, a cost factor per unit of time is applied to the result to determine the associated cost for a given installation duration. This basic methodology will be broken down further by cost category in the following sections.

Cost Estimation Categories

Final cost estimations generated by the Offshore BOS Model are broken down into seven categories, which are based on DOE's system cost breakdown structure (SCBS) (Moné et al. 2015). The SCBS was developed to aggregate costs into specific categories to help users understand the contributions of various wind plant components to the overall system cost. This breakdown can then be used to understand which areas should be the primary focus for cost-reduction strategies. The primary SCBS categories that are represented in the model are development, engineering and management, substructure and foundation, port and staging, electrical infrastructure, assembly and installation, and plant commissioning.

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Development

Project development costs comprise the expenditures that are required to develop early-stage engineering designs referred to as front-end engineering designs (FEEDs). As part of the preliminary design process, the developer is required to conduct site and resource studies to quantify the available energy resource and investigate the potential socioeconomic and environmental impact of the project. As a final step, the developer must obtain the necessary permits, leases, and budget approvals from all state and federal agencies involved to achieve full compliance.

Once the site assessment is complete, the developer will prepare a construction and operation plan, which includes environmental and socioeconomic impact studies as well as detailed plans for construction, impact mitigation, and decommissioning. These plans can be approved, conditionally approved, or denied and the term will typically last 20–30 years (Elkinton et al. 2012).

After all permits and leases are issued and additional compliances are met, the developer may begin installation activities and commissioning of the wind power plant.

Engineering and Management

Engineering and management costs include the costs incurred by the developer for hiring and managing the required personnel (e.g., managers, engineers, and laborers) to carry out engineering designs and fabrication of the components that will make up the wind power plant. The project engineering and management costs are independent of the other CapEx components procured from various suppliers, as the labor and management costs for those items are included in the purchase price.

Substructure and Foundation

Substructure and foundation costs include the procurement cost of the structures that will support the wind turbines. Within the current model version, this cost does not include transportation; future model versions may remedy this limitation. Substructure cost estimates are available for modeling both fixed and floating types. A fixed substructure is one that is secured by a solid connection to the seabed. Examples of fixed substructures available in the model are monopile and jacket. A floating substructure supports the turbine using buoyancy and is secured to the seabed via a mooring and anchor system. Examples of floating substructures available in the model are spar buoy and semisubmersible platform.

Monopile substructures are essentially large steel tubes that are hammered into the seafloor to a specified depth to provide the necessary support for the turbine. These substructures are heavily dependent on the water depth and soil condition at the project site. Very hard, compacted, or rocky soils may require predrilling to install the monopile at additional cost, though there is no adjustment for predrilling costs currently in the model. Monopiles begin to lose their cost effectiveness at water depths greater than 40 meters (m) as a result of the large amount of material required to make a structurally sound pile.

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Jackets are strong, truss lattice structures that are suitable for a variety of soil conditions. Jackets tend to be most cost-effective in water depths ranging from 40 m to 80 m and are sometimes the best option for difficult soil conditions that would require predrilling for monopole installation.

Spar buoys (or "spars") are floating substructures comprising a long, buoyant tube that extends down into the water with ballast at the end to provide overturning resistance and stability. The long draft of the ballasted column that provides the stability limits the spar's viability at water depths greater than 100 m. Special installation procedures are also required to install turbines onto spars, which must be upended to install the turbine. This process usually requires a sheltered inshore assembly with sufficient water depths for upending the spar. Spars and turbine components are ferried to the inshore assembly area where the turbine can be assembled and installed onto the spar. Then, the turbine and substructure assembly can be towed to the project site, positioned, and secured via a mooring and anchor system. It is important to note that this process is sensitive to weather conditions and appropriate weather contingencies should be applied. For information on weather contingency and how it is applied in the model, see the General Parameters in Appendix A.

Semisubmersible platforms (or "semis") are platforms typically made up of three buoyant columns of either steel or concrete that are linked together by a truss system. At the base of each column is a large, flat plate called a heave plate that resists overturning and provides stability. Semisubmersibles have a substantially lower draft than spars, which gives them the advantage of a relatively simple installation procedure and the ability to be installed in water depths ranging from 20 m to 1,000 m or more. For a semisubmersible, the substructure is towed to the installation port where previously staged turbine components are assembled and installed onto it. The entire assembly (substructure and turbine) is then towed to the project site where it is positioned and attached to the preinstalled mooring and anchor system.

Port and Staging

Port and staging costs include costs associated with the installation port and installation activities carried out at the selected port. These costs include fees for the entrance and exit of vessels, docking fees, and wharf fees that are incurred during loading and unloading of turbine and substructure components. Port fees also include the cost of storage and staging of turbine and substructure components that are awaiting pickup by the installation vessel or transport barge. Any cranes used at the port will also incur a cost for the duration of use as well as a mobilization cost.

Electrical Infrastructure

The electrical infrastructure costs include all of the costs that are involved in the procurement of the electrical cabling, power transformer equipment, and ancillary systems necessary for transferring the generated power from the offshore plant to the onshore grid. To estimate these costs, cable sizes and voltages must be specified. The wind plant layout in this model is assumed to be a simple rectangular grid. The model offers the ability to set the spacing between turbines along the same row and between turbine rows. Turbine rows (or "strings") share the same electrical connection back to the offshore substation, wherein power is transferred from the turbine array and then transformed to a higher voltage for transfer to shore. The power is transferred via an export cable or cables to shore, wherein the voltage is transformed again at the

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onshore substation to allow for interconnection with the onshore power grid. Construction and fabrication costs of both the onshore and offshore substations are included in the electrical infrastructure costs; however, this category does not include installation costs for the electrical system as they are included in the assembly and installation costs.

Assembly and Installation

All costs associated with substructure installation, turbine assembly and installation, electrical systems installation, and vessels and equipment installation are included under assembly and installation. Installation costs are driven primarily by the amount of time required to assemble and install the various components. The time needed for installation of the substructure, turbine, and electrical infrastructure is calculated based on the size of the wind power plant, substructure type, and selected installation strategies. The model also assumes a default equipment and vessel spread, which consists of the equipment and vessels required to carry out the various installation operations. Each piece of equipment and vessel has a corresponding day rate that is charged based on the time the equipment or vessel is utilized. The developer will also incur a mobilization cost if the required vessel or piece of equipment must travel a significant distance to the installation port. This cost is assessed in the model as the product of the time needed to mobilize the vessel or equipment and the corresponding day rate. In addition to mobilization costs, the developer may incur costs associated with unsafe installation conditions caused by weather, referred to as weather downtime. The weather downtime is applied after gross installation durations are calculated to find the total, net installation duration. Detailed information about how assembly and installation costs are calculated can be found in Appendix B, Assembly and Installation.

Plant Commissioning

The cost of commissioning the wind power plant includes testing and verifying power generation and control systems, performing turbine safety checks, and conducting any other additional “on-lining” activities. Before the power plant can begin supplying the grid with power, a series of tests and certifications must be carried out to ensure that the wind power plant can be operated safely and that all fail-safe systems are in proper working condition. This process can take several months, as various systems are tested both independently and on a full wind plant system level. Once the plant is confirmed to be operating according to standards and designs, it will be commissioned and begin supplying power to the grid.

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3 Primary Input Parameters

This section will describe the primary inputs to the Offshore BOS Model. The model has well over 100 parameters that can be user defined and the collection of inputs that most users will interact with are referred to as primary input parameters with all others being referred to as detailed input parameters. Primary input parameters are the main drivers of the model and many of these parameters are required for the model to function properly. This section will describe the primary input parameters and how each affects cost estimation outputs.

Number of Turbines

The number of turbines is one of the key descriptors of the modeled wind plant and many of the core functions of the model rely on this input. For example, nameplate capacity of the modeled wind plant will be the number of turbines multiplied by the designated turbine rating and the nameplate capacity is used to derive per-kilowatt costs for the plant. Also, the number of turbines is equal to the number of substructures and these values are used to calculate installation durations and costs for the substructures and turbines. The turbine array layout is also partially dictated by the number of turbines, which affects electrical infrastructure and installation costs. There is a recommended range of values for this input of 3 to 200 to achieve the best results.

Turbine Rating

Turbine rating is another key input, in that many of the relationships within the model scale with it, such as estimation of the turbine and substructure sizes and masses, electrical requirements, and installation durations. It is recommended that a range of 2 MW to 10 MW be used, as the underlying functions are based on data representative of turbine ratings within this range. Turbine rating is used in the following equations found in Appendix B: 1, 5, 6, 9, 11, 13, 15, 19, 21, 23, 25, 27, 29, 32, 35, 37, 38, 39, 40, 65, 71, 72, 85, 86, and 123.

Rotor Diameter

The rotor is a large, rotating subcomponent of the wind turbine that consists of the blades and a rotor hub that forms the interface to the nacelle and contains the blade-pitching mechanisms. The rotor-diameter input is used to estimate dimensions for the turbine-like blade lengths and is also used to determine the turbine array spacing (as specified in units of 'rotor diameters' under sections Array Row Spacing and Array Turbine Spacing). Values must be between 75 and 250 and must be less than double the hub height if there are constraints on the hub height. Rotor diameter is used in Eq. 2, 7, 54, and 59 in Appendix B.

Hub Height

Hub height describes the dimension from the water line to the center of the turbine's rotor hub. The hub height input is used to estimate the tower mass and substructure mass for fixed substructures. Values entered must be less than 150 and greater than the rotor diameter divided by two. Hub height is used in Eq. 7 and 9 in Appendix B.

Water Depth

Water depth is defined in the model as the maximum depth from the water line to the seafloor at the project site. The water depth input has the largest effect on substructure costs and electrical infrastructure costs. The appropriate water depth range depends on the substructure type. For

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fixed substructures—monopile and jacket—a range of 5–100 m is recommended. For semisubmersible substructures, a range of 40–1,000 m is recommended. For spars, a range of 100–1,000 m is recommended. It is important to note that values outside of these ranges will likely yield highly uncertain, and in some cases, erroneous, results. Water depth is used in Eq. 8, 9, 11, 13, 15, 19, 32, 33, 51, 52, 53, 54, 59, 60, and 66 in Appendix B.

Distance to Shore

Distance to shore specifies the straight line distance from the offshore substation to the point where the electrical export cable terminates onshore. It is used in the calculation of export cable lengths and costs. There is no restriction on the range of values that can be entered, but it is important to note that larger values will yield higher electrical infrastructure and overall costs. To see how this input is used specifically, see Appendix B, Electrical Infrastructure, Eq. 66 and 67.

Distance to Installation Port

Distance to installation port is defined as the straight line distance from the center of the turbine array to the installation port. This input is used to calculate installation durations, as it is assumed that installation vessels and/or transport barges will make at least one trip over this distance during construction. There is no restriction on the range of values that can be entered, although a range of 50–500 m is recommended. Also, it is important to make sure that this value makes sense; that is, the wind plant should be a reasonable distance from the installation port. Note that as this value increases so will the costs. This input is used to calculate vessel travel time, which is used in Eq. 89, 96, 97, 103, 106, and 107 in Appendix B, Assembly and Installation.

Substructure and Foundation Type

Substructure and foundation type specifies which substructure type will be used to model the wind plant. In version 2.0 of the Offshore BOS Model, there are two fixed substructure types: monopile and jacket, and two floating substructure types: spar and semisubmersible. This input greatly affects how the model runs calculations because the types of relationships used to calculate costs differ with each substructure type. Further, there are distinct differences in not only the structures themselves, but also the strategies used to install them. It is important to note that some inputs (water depth and turbine rating) have recommended ranges for each substructure type. Care should be taken to ensure that all other inputs align with the type of substructure selected to avoid incorrect calculations. Another important factor to consider is that the substructure relationships were developed assuming a medium-density sand-soil condition and that deviation in the user's assumptions from this particular soil condition will yield greater result uncertainty as this model version has no scaling based on soil condition. For details about how substructures are sized and costs are applied, see Appendix B, Substructure and Foundation.

Distance from Port to Inshore Assembly Area

Distance from port to inshore assembly area is the input that is utilized by the model only when the spar substructure type is selected and affects installation costs. It is assumed that for spar substructures, the substructure will be towed in a horizontal orientation from the port to an inshore assembly area where it will be ballasted and upended. Once upended, the turbine will be installed onto the spar and then the whole assembly will be towed to the project site. There is no

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restriction on the range of values that can be entered, but a range of between 50 m and 500 m is recommended. This input is used in Eq. 90 in Appendix B, Assembly and Installation.

Distance from Inshore Assembly Area to Plant Site

Distance from inshore assembly area to plant site is utilized by the model only when the spar substructure type is selected and affects installation costs. This value will specify the distance from the inshore assembly area, where turbines are installed onto upended spar substructures, to the project site. There is no restriction on the range of values that can be entered, but a range of between 50 m and 500 m is recommended. This input is used to calculate vessel travel time found in Eq. 96 in Appendix B, Assembly and Installation.

Array Row Spacing

Array row spacing specifies the row spacing of the turbine array. The row is also referred to as a string within the model. A row, or string, is a group of turbines that share the same electrical connection to the offshore substation. The input unit is rotor diameters. To find the actual distance in meters, multiply the number of rotor diameters by the rotor diameter input. This dimension is used in combination with the turbine spacing (see next section) to calculate cable lengths and primarily affects electrical infrastructure costs but also has secondary effects on installation costs. There is no restriction on the value that is entered, but a value of at least one should be used (note that large values will significantly increase costs). Nine rotor diameters is a good default value if the row spacing is unknown. The array row spacing is referred to as *String Spacing* in Eq. 59 and 60 in Appendix B, Electrical Infrastructure.

Array Turbine Spacing

Array turbine spacing specifies the spacing of turbines within rows or strings (see previous section for a definition of rows or strings). As with the array row spacing, the input unit is rotor diameters and the actual spacing distance can be found by the method described earlier. With the row and turbine spacing known, the wind plant is modeled as a rectangular grid wherein the row spacing can be assigned to the ‘x’ coordinate and the turbine spacing can be assigned to the ‘y’ coordinate if the grid is visualized in Cartesian coordinates. This dimension is used along with the row spacing (see previous section) to calculate cable lengths and primarily affects electrical infrastructure costs but also has secondary effects on installation costs. Turbine spacing is used in Eq. 53, 54, and 59 in Appendix B, Electrical Infrastructure.

Cable Burial Depth

Cable burial depth describes how deep cables will be buried under the seafloor once installed. It is assumed that, in most cases, cables will be buried; however, in cases where cables will be left unburied, a value of zero can be specified. Cable burial affects installation timing for cable laying operations, so larger values will yield longer installation times and thus higher costs. Values must be between 0 and 5. The cable burial depth is used in Eq. 37, 38, 39, 40, and 65 in Appendix B, Electrical Infrastructure.

Floating Substructure Anchor Type

Anchor type applies only to the floating-type substructures within the model. In this version, there are two selections that can be made: drag embedment anchor (DEA) and suction pile anchor (SPA). A DEA is generally less expensive, but requires greater mooring line length

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because a lead length is required to avoid vertical forces being applied to the DEA, which will cause it to become unanchored. An SPA is generally more expensive, but requires shorter mooring lines because both vertical and horizontal forces can be applied without issue. SPAs also require a specific set of equipment; the costs for which can be set by the following detailed inputs: suction pile spread and vessel day rate and suction pile spread and vessel mobilization/demobilization (Appendix A, Assembly and Installation). Anchor type selection will likely be driven by seafloor characteristics at the project site. If these conditions are unknown, DEA type can be used as a default.

Number of Anchors per Floating Substructure

The number of anchors applies only to the floating-type substructures within the model and affects floating substructure costs. The number of anchors required to attach each substructure and turbine to the seafloor will depend on several factors, such as the size of the turbine installed onto the substructure, the site's weather characteristics, and the seafloor soil conditions. If these factors are unknown and the number of anchors required is unknown, a value of three can be used as the default. This input is also equal to the number of mooring lines that will be modeled, which is referred to as the number of lines in Eq. 80 (Appendix B).

Tower Installation Method

In this version of the model, there are two different installation methods to choose from: one piece and two pieces. One piece assumes that the tower will be transported to the project site in one piece, whereas two pieces assumes that the tower will be transported to the project site in two pieces. The one-piece installation method assumes that towers will be fully assembled before being loaded onto vessels for transport to the project site. This option is generally less costly because only one lift is required to erect the tower, and fully assembled towers typically take up less deck space, which usually requires fewer trips to and from port to transport towers to the project site.

For the two-piece installation method, the tower will be erected at the site by stacking and creating a union between the two pieces to make the assembled tower. This method is generally more costly than the one-piece option, as two lifts are required to erect the tower (one lift for each piece), and the tower being transported in two pieces requires more vessel deck space, which will likely require more trips to and from the port to transport towers to the project site.

Turbine Installation Method

Turbine installation method refers to the tower-top components: the nacelle, blades, and rotor. There are three installation methods that can be selected: individual components, bunny ears, and fully assembled rotor. The individual components option assumes that each component will be installed in sequence. The nacelle will be lifted and installed onto the tower first, then the rotor hub will be lifted and installed onto the nacelle, and the blades will be lifted one by one and installed onto the rotor hub. This option is the most costly, as it requires the most number of lifts and thus greater installation time. The bunny ears option assumes the rotor and two blades will be assembled and mounted on the nacelle before installation at the project site. At the project site, the nacelle with the rotor and two blades attached will be lifted and installed onto the tower and then the remaining blade will be lifted and installed. This option is usually the least costly because it requires only two lifts. In addition, the bunny ears configuration takes up less deck

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space, so fewer trips to and from the port are required to transport turbine components. It is important to note that the bunny ears option requires the heaviest lift, and weather conditions could prohibit such a lift. The fully assembled rotor option assumes that the rotor and all blades will be assembled before installation at the project site. At the project site, the nacelle is lifted and installed onto the tower and then the fully assembled rotor is lifted and installed onto the nacelle. This option requires only two lifts, but more trips to and from port might be required to transport turbine components to the project site—making this option cost somewhere between the bunny ears option and individual components option. It is important to adjust the weather downtime inputs to correlate with the installation method as bunny ears and fully assembled rotor options have heavier lifts that likely require more calm weather conditions. For more insight into how this input affects calculations, see Appendix B, Assembly and Installation: Turbine Installation Time.

Installation Vessel Strategy

For the installation vessel strategy, there are two strategies to choose from: primary installation vessel and feeder barge. The primary installation vessel option is the least expensive option of the two, because it assumes that substructure components will be transported and installed via a primary installation vessel supported by other ancillary vessels. The other option, feeder barge, assumes that the primary installation vessel will remain at the project site for the majority of the installation and components will be delivered to the project site by jack-up barges towed by a tugboat. This option is more costly because of the added expense of using a larger vessel spread as well as an increase in time from the jacking up and lifting operations needed to transfer components from the transport barges. Each strategy has its own weather limitations as well, so it is important to set an appropriate weather downtime input. An important note to be aware of regarding this input is that it affects only cost calculations when modeling fixed substructure types (monopile and jacket).

Number of Installation Seasons

The number of installation seasons specifies the number of vessel mobilizations required to complete the entire installation of the wind plant and affects installation costs. The default value is one; however, it is unlikely that an installation can be completed in only one season for commercial-scale wind plants. The number of installation seasons is used in Eq. 111 in Appendix B, Assembly and Installation.

Substructure and Foundation Installation Weather Downtime

Substructure and foundation installation weather downtime specifies a factor that is used to calculate total substructure installation duration including downtime. The model calculates a gross installation duration for substructure installation that includes all of the time, in days, required to complete installation of all substructures that will be modeled for the specified parameters (the number of substructures is equal to the number of turbines). The downtime input is then applied to adjust the total, or net, installation time for expected weather conditions. For information on how this factor is applied, see Appendix B, Assembly and Installation, Eq. 97 and 98.

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Turbine Installation Weather Downtime

Turbine installation weather downtime is a factor used to calculate the total turbine installation duration including downtime. As it does for substructures, the model calculates a gross duration for the turbine installation that includes the amount of time required to install the entire turbine and tower onto the preinstalled substructures. The weather downtime factor is then used to find the total installation duration including downtime. For information on how this factor is applied, see Appendix B, Assembly and Installation, Eq. 96.

Electrical Installation Weather Downtime

Electrical installation weather downtime is very similar to the aforementioned substructure and turbine installation downtime factors. There is one key difference in that it is applied to three installation timing calculations. The model calculates durations for array cable installation, export cable installation, and offshore substation installation. The factor is then applied to each of these to estimate the total installation duration for the electrical infrastructure components. For more information on the specifics of this calculation, see Appendix B, Assembly and Installation, Eq. 103, 106, and 107.

Interconnect Voltage

Interconnect voltage specifies the voltage of the wind plant's generated electricity once it is converted for distribution to the electrical grid. The default value is 345, which can be changed if the voltage of the grid receiving power from the modeled wind power plant is known. The interconnect voltage is used in Eq. 87 and 88 in Appendix B, Electrical Infrastructure.

Array Cable Voltage

There are two voltage choices to select from in version 2.0 of the Offshore BOS Model: 33 kilovolts (kV) and 66 kV. The 33-kV choice is generally less expensive, but has electrical limitations and increasing losses as the plant nameplate capacity increases. For large plant sizes, the 66-kV option is recommended to minimize losses. It should be noted that this version of the model does not calculate electrical losses but electrical loss assumptions should be taken into account when choosing cables and voltages. If the desired voltage is unknown, then the model has a built-in optimizer that will automatically select cables and voltages based on physical constraints and optimize to achieve the lowest cost.

Array Cable Size #1

The array cable size #1 input is used to connect turbines on the periphery of the array to turbines that are farther from the offshore substation. The model uses two array cable sizes to keep costs low; however, it is possible for more than two sizes of cabling to be used to optimize the cost of the array cabling system. Array cable size #1 is the smaller of the two sizes and can be less than or equal to the size of array cable size #2. This input can be automatically selected by the model via the cable cost optimizer. Array cable length and cost calculations are affected by this input.

Array Cable Size #2

The array cable size #2 input is used to connect turbines close to the substation and make the final connection to the substation. Because array cable #2 will carry more current than array cable #1, it is required that array cable size #2 be equal to or greater than array cable size #1.

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Like array cable #1, the size of array cable #2 can be automatically set via the cable cost optimizer. Array cable length and cost calculations are affected by this input.

Export Cable Voltage

The voltage of the export cable can be set by choosing from one of two voltages in the model: 132 kV or 220 kV. The 132-kV option is generally less expensive, but has electrical limitations and increased losses as both the plant nameplate capacity and the distance from the offshore substation to the onshore substation increase. The 220-kV option is recommended for large plant sizes (> 200 MW) or for smaller plants that are located very far from shore. Again, the model does not compute electrical losses, but it is important to keep electrical loss assumptions in mind when choosing cables and voltages. This input can also be set automatically by the cable cost optimizer.

Export Cable Size

The export cable size can have a dramatic effect on electrical infrastructure costs. The largest driver of cost for the export cable is the number of cables required to safely transfer the generated power from the offshore substation to the onshore substation. A larger cable generally requires fewer cables to transfer the generated power and reduce electrical losses. If it is not known which size is appropriate, the authors recommend using the automatic selection provided by the cable cost optimizer.

Distance to Interconnect from Landfall

This input sets the distance from the export cable landfall point to the grid interconnection point. The model assumes the connection between these points will be made by an overhead transmission line and not a buried cable—the cost of which is calculated by Eq. 87 in Appendix B. Generally, the shorter the distance the lower the cost, but this input is site-specific. If the distance is unknown, the default value of 3 miles can be used.

Turbine Capital Cost

This user-defined input affects plant commissioning calculations. Its primary purpose is to allow for plant commissioning and wind plant levelized cost of energy calculations. This input is not categorized as a BOS cost, and is included in the CapEx variable found in Eq. 125 in Appendix B.

Estimated Port Upgrade Costs

The model assumes that any installation port upgrades and associated costs required to complete installation operations fall under the responsibility of the wind plant developer. Improvements can include structural support upgrades enabling loading, unloading, and storage of turbines and substructures, and entrance and exit upgrades that enable larger vessels to dock. If the estimated port upgrade cost is unknown or no upgrades are needed, use a value of zero.

Scrap Value of Decommissioned Components

The Offshore BOS Model will estimate a decommissioning cost, and part of the process of decommissioning may include scrapping components and reselling the raw materials. The value of these scrapped materials will be deducted from the total decommissioning expense. If no components will be scrapped or the value of these scrapped components is unknown, use a value of zero. This input is used in Eq. 124 in Appendix B, Development.

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4 Verification and Validation

After the initial development, the model had to be verified to ensure proper function and validated to ensure results were consistent with industry data and experience. This confirmation was achieved through a multiphase process that consisted of thorough testing and verification, and internal and external validation.

Testing and Verification

To verify that the model could function as originally designed and produce reliable results, a series of tests were conducted. These tests were designed to exercise the model thoroughly and access all of its functionality in an effort to uncover any defects that could produce erroneous results or cause the model to crash. An example of one of the tests was to iterate the model over a range of inputs and analyze the results. Using this approach, any anomalies in the results were identified and appropriate corrections were implemented.

Internal Validation

To ensure that the model can produce results that are consistent with industry data, several validation exercises were performed. These exercises began with an internal validation by various wind energy analysts within NREL. These analysts ran the model and compared the results from the model with empirical data from industry as well as internal data sets. For example, one test used data from a commissioned and operating offshore wind plant to build a representation of the wind plant in the model. The results from the model were then compared to the data from the existing wind plant to reveal any inconsistencies. This approach allowed the model to be compared against industry data and analyses that were not yet publicly available. One disadvantage of this method is that NREL, even while having considerable resources at its disposal, does not have access to all of the necessary data to validate the model completely. Thus, after internal validation was completed, the model was sent to various industry partners and companies for further validation.

External Validation

NREL sought external validation by distributing the model to various third-party organizations with expertise in the offshore wind industry. The model was sent for review to wind energy experts at Sandia National Laboratories, Offshore Design Engineering Limited, the University of Strathclyde, and others. These industry experts provided feedback on the results and accuracy of the model, which was used to improve the accuracy of results and robustness of the model.

Validation and Verification Results

To protect proprietary information and NREL's partnerships with industry, this section excludes validation and verification results achieved via the use of proprietary or internal data sets. Instead, this section presents the results of a sensitivity analysis conducted to exercise the model and ensure that the model can make reasonably accurate cost estimations and to identify and 'strange' behavior that could lead to erroneous results. The approach of this analysis was to select key driving inputs and increment these inputs over a range to determine the sensitivity of the outputs to the selected inputs.

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The key inputs that were selected were plant size or nameplate capacity, turbine size or rating, water depth, cable size and array spacing, and logistical distances. In addition, a fixed substructure (monopile and jacket) and floating substructures (spar and semisubmersible) were analyzed separately to ensure that cost estimations for each substructure type are accurate. A summary of the following results was presented at the American Wind Energy Association Offshore WINDPOWER 2015 conference. Results were normalized to reflect percent changes compared to a baseline 600-MW wind plant (the parameters for which are shown in

Table 2 and Figure 1, which provides a legend for the results presented by cost estimation category; model defaults were used for parameters not listed in Table 2). Note that the results presented here are meant to demonstrate the capabilities of the Offshore BOS Model rather than to compare fixed versus floating substructures, and in cases where result trends are similar across substructure types, substructure-independent results are presented. Also, these results should be taken as representative only because of the high level of variability of project parameters and site-specific elements.

Table 2. Sensitivity Analysis Parameters for a Baseline Wind Plant

Baseline Parameters (Fixed Substructure/Floating Substructure)	
Project Size (MW)	600
Turbine Rating (MW)	6
Rotor Diameter (m)	154
Hub Height (m)	90
Distance to Shore (km)	40
Distance to Installation Port (km)	40/60
Water Depth (m)	25/250
Array Spacing (rotor diameters)	9 x 9
Capacity Factor (%)	40

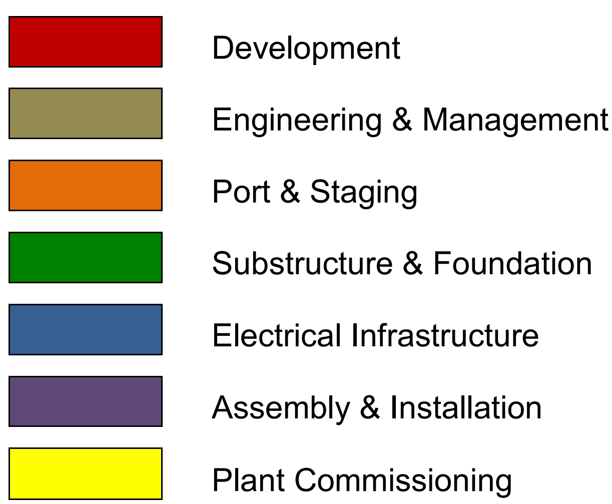

Figure 1. Cost estimation category legend

Figure 2 provides the results for the sensitivity to plant size (holding turbine rating constant) for the monopile substructure. The figure shows high costs at small plant sizes with decreasing costs as plant size increases. Eventually costs begin to increase gradually with increased plant size, which is caused by an overestimation of cable lengths. As the plant size increases, the size of the turbine array and the length of the cables leading from strings to the substation also increase. This increase is a result of the array being modeled as a rectangular grid. In reality, the array layout would be optimized for energy capture and the cable lengths would be minimized to reduce cost. Without this model limitation, per-megawatt costs are expected to continue decreasing as plant size increases as a result of fixed BOS costs being distributed over greater energy production capacity.

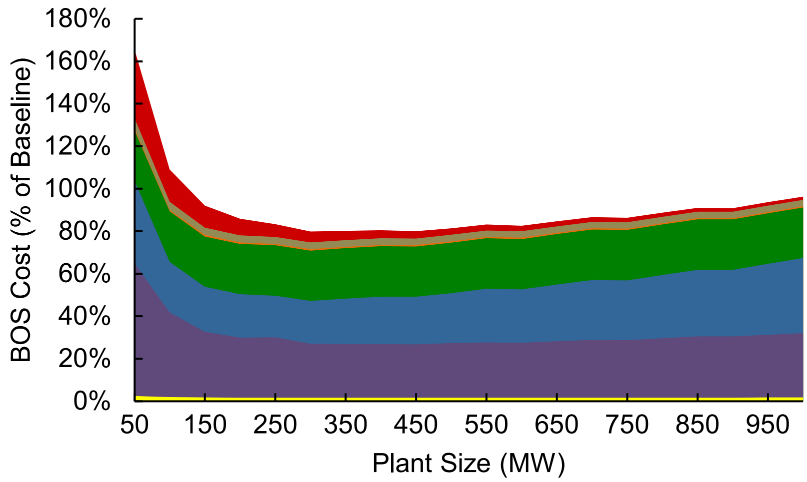

Figure 2. Sensitivity to plant size (substructure-independent)

Figure 3 shows the sensitivity to water depth for fixed and floating substructures. For fixed substructures, water depth has the largest effect on substructure costs. For floating substructures, the water depth affects substructure, installation, and electrical costs because mooring line and cable lengths as well as installation durations increase, which is partly because of the greater water depths and water depth deltas visualized on the floating substructure graph. The largest difference between the two graphs in Figure 3 is the change in substructure costs. Floating substructure mass, unlike fixed substructure mass, scales independently of water depth and the slight increase in substructure cost seen in the floating substructure graph is caused by increased mooring line length. Overall, fixed substructures within the model have a much greater cost sensitivity to water depth.

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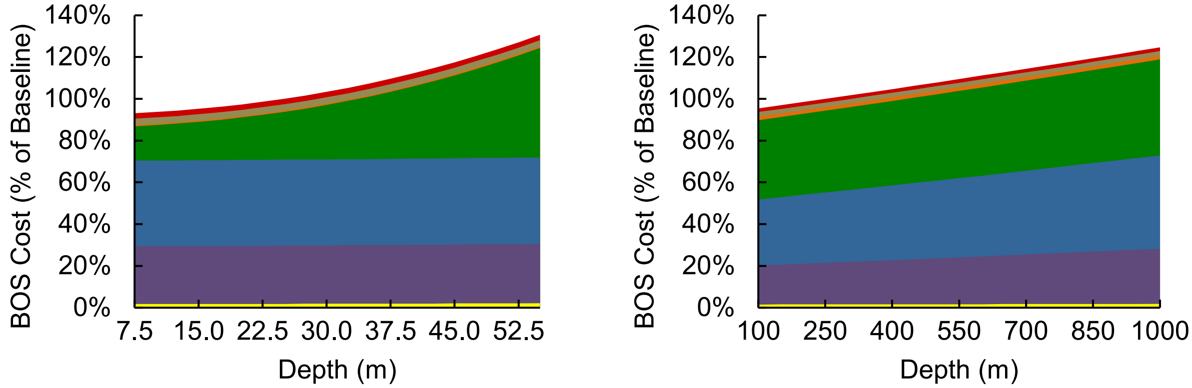

Figure 3. Sensitivity to water depth ([left] fixed substructure; [right] floating substructure)

As seen in Figure 4, costs decrease as turbine rating increases because fewer turbines are required to reach a given energy production capacity. The primary driver of this cost decrease is the reduction in installation costs caused by shorter installation durations. Though it should be noted that installation costs are also heavily driven by vessel selection and increases in turbine size may require larger, more expensive vessels. Substructure costs also decline slightly as a result of fewer total substructures and associated reductions in installation time.

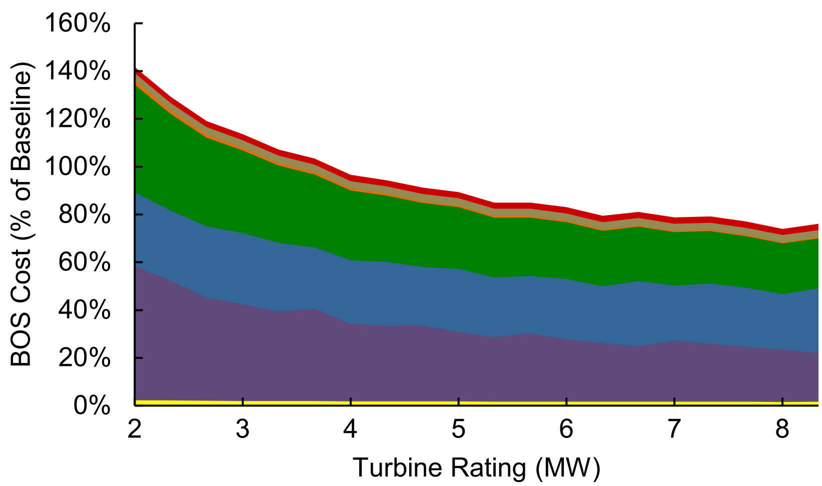

Figure 4. Sensitivity to turbine rating (substructure-independent)

In Figure 5, the sensitivity to the distance to shore is shown. As expected, electrical infrastructure costs are increasing with distance because the export cable length is increasing. There is also a slight increase in installation costs resulting from the increase in time required to install a longer export cable.

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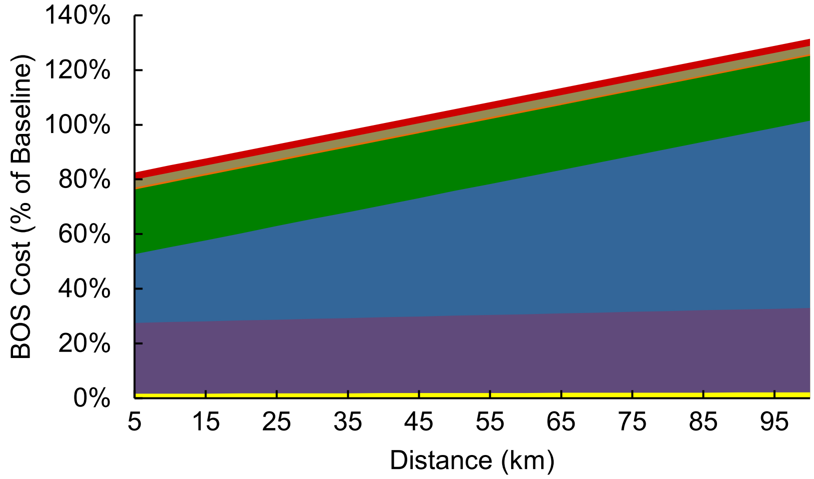

Figure 5. Sensitivity to distance to shore (substructure-independent)

Figure 6 provides the sensitivity to the export cable size. The export cable size, along with the selected voltage, will determine how many export cables are necessary to safely transfer the generated power to shore. Smaller-sized cables are less costly per unit length but may require more individual cables to safely transfer the power. There is an optimal size for this specific case (shown in Figure 6) at cable size 1,200 mm^2, in which the overall cost is at its lowest. At this size, fewer export cables are needed than for cables smaller than 1,200 mm^2, so the overall length of the export cable system is shorter, which offsets the greater cost-per-unit length of the 1,200 mm^2 cable. At sizes greater than 1,200 mm^2, the same number of export cables are needed to transfer the power as the 1,200-mm^2 size, but the greater cost-per-unit length of the larger cables cause overall costs to begin increasing again. The optimal cable size will fluctuate depending on plant nameplate capacity.

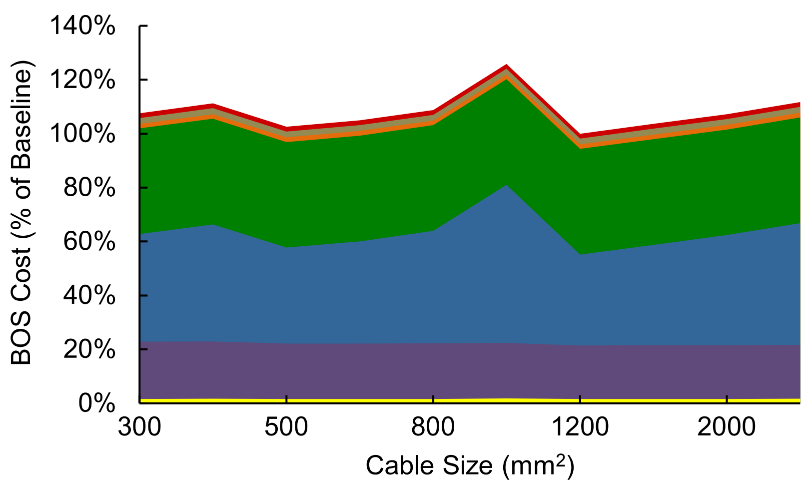

Figure 6. Sensitivity to export cable size (substructure-independent)

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5 Discussion and Conclusions

NREL analysts set out to build a tool that could help the wind industry and researchers better understand the major costs and cost drivers of developing an offshore wind plant. Overall, the Offshore BOS Model can be considered effective in meeting this objective. The model fills a gap not previously publicly available in any other tool and produces results consistent with industry data. Although the model is relatively effective at estimating offshore wind plant BOS costs, there are some key strengths and weaknesses that will be discussed here, with a brief summary of some of the published analyses that have utilized the model thereafter.

The key strengths of the model include over 100 user-defined inputs, electrical cabling cost optimization capabilities, computationally inexpensive and verified results. The user-defined inputs can be customized, and with the appropriate expertise users can achieve accurate results with minimal uncertainty. For very advanced users, this allows for in-depth analysis of the cost drivers of offshore wind plant BOS components. The electrical cable cost optimization provides the ability to automatically select cable sizes and voltages, which in cases where these parameters are not known an appropriate and cost-effective option can be automatically selected. The model runs on an average laptop in less than 100 milliseconds, which allows for very fast sensitivity analyses that may require several thousand runs of the model. Finally, results have been verified that give the user confidence that generated outputs are within realistic limits.

The model itself is fairly complex but not comprehensive. Further, there are several weaknesses that should be taken into account when using it. The first relates to electrical infrastructure and the way the turbine array is modeled. Because the array is modeled as a simple rectangular grid, the distance from the offshore substations to the first turbine in a string increases for each new string as the number of turbines increases. This means that array cable lengths become increasingly overestimated at large plant sizes (> 50 turbines). In reality, the array layout for a project will be optimized depending on seafloor characteristics, energy capture, and array cable lengths. Another notable weakness relates to substructure costs. In version 2.0 of the model, there is no consideration of seafloor soil condition, which is generally a driver of substructure selection and costs. Finally, many of the scaling relationships within the model are parabolic and have positive slopes within the recommended ranges of the inputs. Outside of these recommended ranges, the slopes of these relationships may go negative, which can lead to negative outputs and in rare cases division by zero. It is important to take note of the recommended ranges given in the descriptions of the inputs.

Recent peer-reviewed publications that have utilized the Offshore BOS Model to inform their analyses include the *National Offshore Wind Strategy: Facilitating the Development of the Offshore Wind Industry in the United States* (Gilman et al. 2016), *A Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030* (Beiter et al. 2016), and the forthcoming *2015 Cost of Wind Energy Review* (Moné et al. 2016).

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

6 Recommendations for Future Development

Here we provide a brief overview of future additions and improvements that will address some of the aforementioned weaknesses of the Offshore BOS Model. The first weakness is the model's overestimation of electrical infrastructure costs. Ideally, to solve this issue, some form of turbine array optimization should be implemented that could place turbines closer to the offshore substation with the goal of reducing cable run lengths to get a more realistic layout and thus cost estimations. Regarding soil condition, it would be a major improvement to update the substructure sizing and selection algorithms to account for a more site-specific soil condition. However, this enhancement may require a large data collection effort. Lastly, because the offshore wind industry is constantly changing, it may be a worthwhile investment to provide users with updated cost factors and scaling relationships based on new data.

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.

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Appendix

A. Inputs: Key Assumptions and Caveats

General Detailed Inputs

Inspection Clearance: The inspection clearance is the distance that is required to walk around and inspect the laydown area for turbine and substructure components. The default clearance is 2 m.

Economic Lifetime: The economic lifetime is the time that the wind plant will be in operation from the commissioning date to the shutdown date for decommissioning. The default value is 20 years.

Development

Plant Commissioning: The percent of the total cost of the wind plant development and construction estimated to make up wind plant commissioning. The default value is 1%.

Decommissioning Cost Discount Rate: The rate at which the future decommissioning expense value is discounted to equal present worth.

Pre-Front-End Engineering Design Study: The cost of the initial development and design process (or pre-FEED). The default value is $5 million.

FEED Study: The cost of the design process that takes place after preliminary low-detail design and before the highly detailed final design process. The default value is $10 million.

State Leasing Process: The cost of the state-level leasing process in the state where the facility will be commissioned. States have jurisdiction in coastal waters within 3 nautical miles of shore. Florida and Texas have jurisdiction up to 9 nautical miles off shore. The default value is $250,000.

Outer Continental Shelf Leasing Process: The Bureau of Ocean Energy Management (BOEM) leasing process requires submission of a site assessment plan and environmental assessments. The default cost for this process is $1 million.

Site Assessment Plan: The site assessment plan is part of the BOEM leasing process. The default cost is $500,000.

Construction Operation Plan: The construction operation plan is part of the BOEM leasing process. The default cost is $1 million.

National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS) Meteorological Tower: Developers are required to perform an EIS to explore the potential environmental effects of the proposed wind plant. The default cost is $2 million.

Physical Resource Studies—Met Tower: The cost of activities related to obtaining and analyzing physical resource data from met towers. The default cost is $1.5 million.

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Biological Resource Studies—Met Tower: The cost of activities related to obtaining and analyzing biological resource and impact data from met towers. The default cost is $1.5 million.

Socioeconomic and Land-Use Studies—Met Tower: The cost of activities related to obtaining socioeconomic and land-use data and information from met towers. The default cost is $200,000.

Navigation and Transportation Studies—Met Tower: The cost of activities related to obtaining transportation and navigation data from meteorological towers. The default cost is $250,000.

NEPA EIS—Project: The costs associated with NEPA compliance and EIS. The default cost is $5 million.

Physical Resource Studies—Project: The cost of activities related to project-level physical resource data collection and analysis. The default cost is $500,000.

Biological Resource Studies—Project: The cost of activities related to project-level biological resource data collection and analysis. The default cost is $500,000.

Socioeconomic and Land-Use Studies—Project: The cost of activities related to project-level socioeconomic and land-use data collection and analysis. The default cost is $200,000.

Navigation and Transportation Studies—Project: The cost of activities related to project-level transportation and navigation data collection and analysis. The default cost is $250,000.

Coastal Zone Management Act Consistency: The cost of compliance to ensure federal policies are enforced and in line with state and local policies. The default cost is $100,000.

Rivers and Harbors Act, Section 10: The cost of approving projects located in navigable waters, which must be approved under the Rivers and Harbors Act, Section 10. The default cost is $100,000.

Clean Water Act, Section 404: The costs associated with Clean Water Act, Section 404, compliance. The default cost is $100,000.

Clean Water Act, Section 402: The costs associated with Clean Water Act, Section 402, compliance. The default cost is $100,000.

Federal Aviation Administration Plans and Mitigation: The costs associated with this approval process to ensure that the proposed wind plant will not have significant detrimental effects on aviation radar and navigation systems. The default cost is $10,000.

Endangered Species Act: The costs associated with assessing the impacts a project might have on endangered species inhabiting the project site and surrounding area. The default cost is $500,000.

Marine Mammal Protection Act: The costs associated with assessing and minimizing the potential impacts the project might have on marine mammals within the site area. The default cost is $500,000.

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Migratory Bird Treaty Act: The costs associated with assessing the potential risks a project might pose to migratory bird populations and their migration paths. The default cost is $500,000.

National Historic Preservation Act: The costs associated with conducting archaeological and historic assessments of the potential risks posed by a project. The default cost is $250,000.

Additional State and Local Permitting: The costs associated with securing any additional permits and approvals and developing management plans. The default cost is $200,000.

Met Tower Fabrication and Installation: Estimated cost of met tower fabrication and installation per megawatt of plant nameplate capacity. The default cost is $11,518 per MW.

Engineering and Management

Detailed Monopile Design—Primary: The cost of primary, detailed monopile substructure engineering design. The default value is $1.5 million.

Detailed Jacket/Gravity-Base Substructure Design—Primary: The cost of primary, detailed jacket or gravity-base substructure engineering design. The default value is $3 million.

Detailed Design—Secondary Steel: The cost of detailed engineering design for any secondary steel component (such as ladders, walkways, and boat landings). The default value is $600,000.

Staffing and Overhead: The cost per kilowatt (kW) of all staffing and overhead costs related to hired personnel. The default value is $60 per kW.

Estimated Engineering and Management Cost Factor: The percentage of all hard costs (such as procurement and installation), which is used to calculate the total engineering and management cost for a modeled wind plant. The default value is 4%.

Port and Staging

Vessel Entrance and Exit: The cost in dollars per exit or entrance occurrence. The model uses per square meter of vessel footprint area or the length of the vessel multiplied by the breadth of the vessel ($/m^2/occurrence). The default value is $0.53 per m^2 per occurrence.

Quayside Docking: The cost in dollars per day of quayside for vessel docking. The model uses the entire installation duration to determine the total quayside docking cost. The default value is $3,000 per day.

Loading/Unloading/"Wharf age": The dollar-per-tonne cost of loading and unloading operations at the port. This includes all turbine and substructure loading and unloading at the installation port. The default value is $2.80 per tonne.

Open Storage: The cost in dollars per square meter of laydown space per day. The laydown space is the space required at or near the installation port that is used to store turbine and substructure components to be installed that are waiting to be loaded onto an installation vessel. The default value is $0.25 per m^2 per day.

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600 Tonne (crane): The dollar-per-day cost of a crawler crane that is the smaller of the two cranes available within the model. This crane has a 600-tonne capacity, and the default value is $5,000 per day.

1,000 Tonne (crane): The dollar-per-day cost of a crawler crane that is the larger of the two cranes available within the model. This crane has a 1,000-tonne capacity, and the default value is $8,000 per day.

Crawler Crane Mobilization and Demobilization: The cost of mobilizing and demobilizing any cranes that are used for installation of the modeled wind plant in dollars per project (e.g., one rate is charged per crane for the entire project). The default value is $150,000 per project.

Self-Propelled Modular Transport Units (SPMTs): The cost of modular transport units that "cart" components to their desired location without requiring a crane and lifting operations. The default value is $1.50 per tonne per day.

Substructure and Foundation

Pile Cost (monopile): The cost per tonne of the steel tubular structure that makes up the main component of the monopile substructure. A monopile is driven into the seafloor in shallow to moderate water depths. This cost is for procurement only and not installation. The default value is $2,250 per tonne.

Pile Length (monopile): The length of the pile that is driven into the seafloor. This input is needed to calculated laydown area and how many piles can fit onto the cargo deck of the selected vessel. The default value is 560 m.

Pile Embedment Length (monopile): The length required to be driven into the seafloor to safely support the turbine and substructure. This value should be adjusted along with turbine size to ensure the turbine is supported properly. The default value is 30 m.

Pile Diameter (monopile): The diameter of the pile driven into the seafloor to support the turbine. The default value is 10 m.

Transition Piece Cost (monopile): The procurement cost of the transition piece used to connect the base of the turbine to the top of the monopile. The default value is $3,230 per tonne.

Scour Protection Material Cost: The cost per tonne of the scour protection required for monopile installations. Scour protection prevents the soil on the seafloor from being carried away by ocean currents, which could have a negative impact the ability of the pile to support the turbine. The default value is $250,000 per tonne.

Main Lattice Cost (jacket): The cost per tonne of the main lattice of the jacket-type substructure. A jacket is a truss structure that can be installed in moderate to deep waters. The default value is $4,680 per tonne.

Main Lattice Footprint (jacket): The footprint area of the main lattice in square meters. The jacket is assumed to upright. The default value is 226 m^2.

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Transition Piece Cost (jacket): The cost per tonne of the transition piece that connects the top of the main lattice to the bottom of the turbine tower. The default value is $4,500 per tonne.

Piles Cost (jacket): The cost per tonne of the piles that are driven into the seafloor and secure the main lattice to the seafloor.

Pile Length (jacket): The length of the piles that are driven into the seafloor. The default value is 293 m.

Pile Diameter (jacket): The diameter of the piles that are driven into the seafloor. The default value is 2 m.

0.09 m Diameter (spar): The cost per meter of the smallest mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $399 per meter.

0.12 m Diameter (spar): The cost per meter of the mid-sized mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $721 per meter.

0.15 m Diameter (spar): The cost per meter of the largest mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $1,088 per m.

Drag Embedment Fixed Mooring Length (spar): The fixed, slack length of the mooring line required for drag embedment anchors to prevent vertical forces, which could pull drag embedment anchors out, causing the substructure and turbine to drift away from their desired location. The default value is 500 m.

Stiffened Column Cost (spar): The cost per tonne of the stiffened column, which is the portion of a spar-type substructure that provides the buoyancy to float the turbine and substructure. The default value is $3,120 per tonne.

Tapered Column Cost (spar): The cost per tonne of the tapered column, which is the portion of the spar-type substructure where the turbine attaches. The default value is $4,222 per tonne.

Ballast Cost (spar): The cost per tonne of the ballast that keeps the spar substructure upright in the water. The default value is $100 per tonne.

0.09 m Diameter (semisubmersible): The cost per meter of the smallest mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $399 per meter.

0.12 m Diameter (semisubmersible): The cost per meter of the mid-sized mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $721 per meter.

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0.15 m Diameter (semisubmersible): The cost per meter of the largest mooring line diameter available in the model. The mooring line is used to connect floating substructures to the anchors that secure the substructures to the seafloor. The default value is $1,088 per meter.

Drag Embedment Fixed Mooring Length (semisubmersible): The fixed, slack length of the mooring line required for drag embedment anchors to prevent vertical forces, which can pull drag embedment anchors out and cause the substructure and turbine to drift away from their desired location. The default value is 500 m.

Stiffened Column Cost (semisubmersible): The cost per tonne of the stiffened column that provides the buoyancy to float the turbine and substructure. The default value is $3,120 per tonne.

Truss Cost: The cost per tonne of the truss system that connects stiffened columns together to form the semisubmersible substructure. The default value is $6,250 per tonne.

Heave Plate Cost: The cost per tonne of the heave plate, which is an underwater portion of the semisubmersible substructure that aids in reducing the motion imparted on the substructure by ocean waves and currents. The default value $6,250 per tonne.

Outfitting Steel Cost: The cost per tonne of the outfitting steel for all substructure types. Secondary to structural components, outfitting steel includes ladders, boat landings, walkways, and railings. The default value is $7,250 per tonne.

Electrical Infrastructure

Power Factor: A percentage that accounts for power transfer efficiency expected from the power transfer and cabling system being modeled. The default value is 95%, meaning that when this factor is applied, the assumed efficiency is 95% and electrical losses from the cables are 5%.

Burial Depth Factor: A derating factor that determines the maximum amount of current that can be transferred through a buried cable. Generally, because of thermal loading, a buried cable cannot carry as much current as an unburied cable. This factor helps ensure that the buried cable can be used safely without an overcurrent issue leading to premature cable failure.

Excess Cable Factor: A contingency percentage of cable length added to ensure that all cabling is of the proper length. The default value is 10%.

Catenary Length Factor: A percentage of additional length to free-hanging cables used for floating substructures that enables the cable to hang slack in the water and reduces seafloor abrasion that might cause premature cable failure. The default value is 4%.

Dynamic Cable Cost Premium Factor: Additional cost applied to the cable cost calculation of free-hanging cables used for floating substructure projects. The model assumes that dynamic cables are designed to withstand forces from ocean currents and wave motion, which likely adds a significant cost to the production of dynamic cables compared to standard buried cables. The default value is 2.

Fabrication Cost: The dollar-per-tonne cost of the offshore substation's topside fabrication and related activities. The substation topside refers to all structures that remain above the water line once installed. The default value is $14,500 per tonne.

Design Cost: The cost of the offshore substation's topside design process. The default value is $4.5 million.

Jacket Cost: The dollar-per-tonne cost of the offshore substation's jacket substructure. Used for fixed substructure projects, which assume that the offshore substation will be installed onto a jacket-type substructure. The default value is $6,250 per tonne.

Pile Cost: The dollar-per-tonne cost of the piles used to secure the offshore substation's jacket substructure to the seafloor. The default value is $2,250 per tonne.

MPT Cost: The dollar-per-megavolt-ampere (MVA) cost of the main power transformers that transform the generated power so it can be transferred to shore. The default value is $12,500 per MVA.

High-Voltage Switchgear: The cost of the high-voltage switchgear used to control electrical current and protect the high-voltage electrical components housed within the offshore substation. The default value is $950,000.

Medium-Voltage Switchgear: The cost of the high-voltage switchgear used to control electrical current and protect the medium-voltage electrical components housed within the offshore substation. The default value is $500,000.

Offshore Shunt Reactors: The dollar-per-MVA of the offshore shunt reactors used to stabilize voltage in high-voltage energy transfer systems. The default value is $35,000 per MVA.

Diesel Generator Backup: The cost of the backup diesel generators needed to supply power to all necessary systems should the wind plant be rendered unable to generate its own power. The default value is $1 million.

Workshop, Accommodations, Fire Protection System: The cost of the offshore substation fire protection system and the cost of work space and accommodations for operations and maintenance personnel. The default value is $2 million.

Other Ancillary Costs: The cost of any additional or ancillary components or systems required for a fully functioning offshore substation. The default value is $3 million.

Assembly and Installation

Piling Spread Day Rate: The per-day cost of any equipment, excluding the main installation and ancillary vessels, required to complete installation of any piles that will be driven into the seafloor to anchor components or substructures at the project site. The default cost $2,500 per day.

Piling Spread Mobilization/Demobilization: The total cost of mobilizing and demobilizing the equipment to be used for piling spread project installation activities. This includes costs for

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readying pile hammers and other equipment used to drive piles into the seafloor. The default cost is $750,000.

Grouting Spread Day Rate: The cost per day of any equipment, excluding the main installation and ancillary vessels, required to install the grouting that will secure, for example, a transition piece to a monopile foundation. The default cost is $3,000 per day.

Grouting Spread Mobilization/Demobilization: The total cost of mobilizing and demobilizing the equipment required for grouting operations. The default cost is $1 million.

Suction Pile Spread and Vessel Day Rate: The cost per day of the equipment and vessels required to install suction pile anchors for floating substructures. The default cost is $165,000 per day.

Suction Pile Spread and Vessel Mobilization/Demobilization: The total cost of mobilizing and demobilizing the equipment and vessels required for the installation of suction pile anchors for floating substructures. The default cost is $4.5 million.

Component Racks: The total cost of racks used to secure and stabilize turbine components during transport via vessel or barge to the project site. Component racks are not used when modeling wind plants installed on semisubmersible substructures because turbine installation takes place at the installation port, and the turbine and substructure are towed to the project site for installation. The default cost is $1 million.

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B. Calculated Values: Assumptions and Caveats

General

Hub Diameter: Simple relationship that scales with turbine rating. Values calculated in meters.

$$\frac{Turbine\ Rating}{4} + 2 \qquad (1)$$

Blade Length: Simple relationship that scales with rotor diameter and hub diameter. Values calculated in meters.

$$\frac{(Rotor\ Diameter - Hub\ Diameter)}{2} \qquad (2)$$

Nacelle Width: Simple relationship that scales with hub diameter. Values calculated in meters.

$$Hub\ Diameter + 1.5 \qquad (3)$$

Nacelle Length: Simple relationship that scales with nacelle width. Values calculated in meters.

$$2 \cdot Nacelle\ Width \qquad (4)$$

Rotor Nacelle Assembly Mass: Polynomial curve fit relationship developed using available mass data for turbines ranging from 2 MW to 6 MW. Scales with turbine rating. Values calculated in tonnes.

$$2.082 \cdot (Turbine\ Rating)^2 + 44.59 \cdot Turbine\ Rating + 22.48 \qquad (5)$$

Tower Diameter: Simple relationship that scales with turbine rating. Values calculated in meters.

$$\frac{Turbine\ Rating}{2} + 4 \qquad (6)$$

Tower Mass: Curve fit relationship developed from available tower mass data that scales with hub height and rotor diameter. Values calculated in tonnes.

$$\frac{\left(0.4 \cdot \pi \cdot \left(\frac{Rotor\ Diameter}{2}\right)^2 \cdot Hub\ Height - 1500\right)}{1000} \qquad (7)$$

Substructure and Foundation

Monopile Length: Simple relationship that scales with water depth and embedment depth of the monopile foundation. Assumes a 5 m length above the water line. Values calculated in meters.

$$Water\ Depth + Embedment\ Depth + 5 \qquad (8)$$

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Monopile Mass: Curve fit relationship that scales with turbine rating, hub height, water depth, and rotor nacelle assembly mass. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$\frac{\left((Turbine\ Rating \cdot 1000)^{1.5} + \frac{(Hub\ Height)^{3.7}}{10} + 2100 \cdot (Water\ Depth)^{2.25} + (RNA\ Mass \cdot 1000)^{1.13}\right)}{10000} \tag{9}$$

Monopile Cost: Simple relationship that scales with monopile mass and a cost rate per unit mass in tonnes.

$$Monopile\ Mass\ \cdot\ Monopile\ Cost\ Rate \tag{10}$$

Monopile Transition Piece (TP) Mass: Curve fit relationship that scales with turbine rating and water depth. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$e^{2.77\,+\,1.04\,\cdot(Turbine\ Rating)^{0.5}+0.00127\,\cdot(Water\ Depth)^{1.5}} \tag{11}$$

Monopile TP Cost: Simple relationship that scales with monopile TP mass and a cost rate per unit mass in tonnes.

$$Monopile\ TP\ Cost = Monopile\ TP\ Mass\ \cdot\ Monopile\ TP\ Cost\ Rate \tag{12}$$

Jacket Main Lattice (ML) Mass: Curve fit relationship that scales with turbine rating and water depth. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$e^{3.71+0.00176\,\cdot\,(Turbine\ Rating)^{2.5}+0.645\,\cdot\,\ln\left((Water\ Depth)^{1.5}\right)} \tag{13}$$

Jacket ML Cost: Simple relationship that scales with jacket ML mass and a cost rate per unit mass in tonnes.

$$Jacket\ ML\ Mass \cdot Jacket\ ML\ Cost\ Rate \tag{14}$$

Jacket TP Mass: Curve fit relationship that scales with turbine rating and water depth developed using data generated from a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$\frac{1}{\left(\frac{-0.0131 + 0.0381}{\ln(Turbine\ Rating)} - 0.00000000227 \cdot (Water\ Depth)^{3}\right)} \tag{15}$$

Jacket TP Cost: Simple relationship that scales with jacket TP mass and a cost rate per unit mass in tonnes.

$$Jacket\ TP\ Mass \cdot Jacket\ TP\ Cost\ Rate \tag{16}$$

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Jacket Pile Mass: Curve fit relationship that calculates the total mass for four piles based on the jacket ML mass. Values calculated in tonnes.

$$8 \cdot (Jacket\ ML\ Mass)^{0.5574} \tag{17}$$

Jacket Pile Cost: Simple relationship that scales with jacket pile piece mass and a cost rate per unit mass in tonnes.

$$Jacket\ Pile\ Mass \cdot Jacket\ Pile\ Cost\ Rate \tag{18}$$

Spar Stiffened Column (SC) Mass: Curve fit relationship that scales with turbine rating and water depth. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$535.93 + 17.664 \cdot (Turbine\ Rating)^2 + 0.02328 \cdot Water\ Depth \cdot \ln(Water\ Depth) \tag{19}$$

Spar SC Cost: Simple relationship that scales with spar SC mass and a cost rate per unit mass in tonnes.

$$Spar\ SC\ Mass \cdot Spar\ SC\ Cost\ Rate \tag{20}$$

Spar Tapered Column (TC) Mass: Curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$125.81 \cdot \ln(Turbine\ Rating) + 58.712 \tag{21}$$

Spar TC Cost: Simple relationship that scales with spar tapered column mass and a cost rate per unit mass in tonnes.

$$Spar\ TC\ Mass \cdot Spar\ TC\ Cost\ Rate \tag{22}$$

Spar Ballast Mass: Curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Includes both permanent and variable ballast. Values calculated in tonnes.

$$-16.536 \cdot (Turbine\ Rating)^2 + 1261.8 \cdot Turbine\ Rating - 1554.6 \tag{23}$$

Spar Ballast Cost: Simple relationship that scales with spar ballast mass and a cost rate per unit mass in tonnes.

$$Spar\ Ballast\ Mass \cdot Spar\ Ballast\ Cost\ Rate \tag{24}$$

Semisubmersible (SS) SC Mass: Curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Values calculated in tonnes.

$$-0.9571 \cdot (Turbine\ Rating)^2 + 40.89 \cdot Turbine\ Rating + 802.09 \tag{25}$$

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SS SC Cost: Simple relationship that scales with SS SC mass and a cost rate per unit mass in tonnes.

$$SS\ SC\ Mass \cdot SS\ SC\ Cost\ Rate \tag{26}$$

SS Truss Mass: Curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Includes both permanent and variable ballast. Values calculated in tonnes.

$$2.7894 \cdot (Turbine\ Rating)^2 + 15.591 \cdot Turbine\ Rating + 266.03 \tag{27}$$

SS Truss Cost: Simple relationship that scales with semisubmersible truss mass and a cost rate per unit mass in tonnes.

$$SS\ Truss\ Mass \cdot SS\ Truss\ Cost\ Rate \tag{28}$$

SS Heave Plate Mass: Curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. Includes both permanent and variable ballast. Values calculated in tonnes.

$$-0.4397 \cdot (Turbine\ Rating)^2 + 21.545 \cdot Turbine\ Rating + 177.42 \tag{29}$$

SS Heave Plate Cost: Simple relationship that scales with semisubmersible heave plate mass and a cost rate per unit mass in tonnes.

$$SS\ Heave\ Plate\ Mass \cdot SS\ Heave\ Plate\ Cost\ Rate \tag{30}$$

Mooring and Anchor System Cost: An algorithm that determines the mooring line diameter in standard sizes, the mooing line length, and the mooring line minimum breaking load from a curve fit relationship that scales with turbine rating. Developed from data generated by a more sophisticated NREL internal substructure sizing model. The mooring line length also depends on the type of anchor selected. The anchor cost is then calculated, depending on anchor type, from curve fits that scale with mooring line breaking loads that were generated using data obtained from various NREL industry partners. The mooring line cost is a simple relationship that scales with mooring line length and a cost rate per unit length determined based on mooring line diameter. The total mooring and anchor system cost is the sum of the anchor cost and the mooring line cost. Steel chain is the assumed mooring type.

$$Mooring\ Length \cdot Mooring\ Cost\ Rate + Anchor\ Cost \tag{31}$$

Secondary Steel Mass: An algorithm that calculates secondary steel mass using curve fits. Developed from data generated by more sophisticated NREL internal substructure sizing models as well as data from industry partners. The secondary steel mass depends on the selected substructure type; for fixed substructure types, secondary steel mass also depends on the turbine rating. The relationships for fixed-type substructures scale with water depth, and the relationships for floating-type substructures scale with water depth and turbine rating. In addition to the structural steel required to support the wind turbine, secondary steel components include ladders, railing, walkways and boat landings. Values calculated in tonnes.

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Fixed Substructure:

$$\begin{cases} Turbine\ Rating \leq 4, 35 + \left(0.8 \cdot (18 + Water\ Depth)\right) \\ Turbine\ Rating > 4, 40 + \left(0.8 \cdot (18 + Water\ Depth)\right) \end{cases} \tag{32}$$

Spar Substructure:

$$e^{3.58+0.196\cdot(Turbine\ Rating)^{0.5}\cdot\ln(Turbine\ Rating)+0.00001\cdot Water\ Depth\cdot\ln(Water\ Depth)} \tag{33}$$

Semisubmersible substructure:

$$-0.153 \cdot (Turbine\ Rating)^2 + 6.54 \cdot Turbine\ Rating + 128.34 \tag{35}$$

Secondary Steel Cost: Simple relationship that scales with secondary steel mass plate mass and a cost rate per unit mass in tonnes.

$$Secondary\ Steel\ Mass \cdot Secondary\ Steel\ Cost\ Rate \tag{36}$$

Electrical Infrastructure

Number of Strings: Scaling relationship that determines the total number of turbines that will be connected to the offshore substation via an electrical line (or string). The relationship scales with the number of turbines, the turbine rating, the current rating of the array cabling, the array cable system voltage, the power factor, the cable burial depth, and the cable burial depth factor.

$$Round\ Down\left(\frac{Number\ of\ Turbines \cdot Turbine\ Rating}{\sqrt{3} \cdot Cable\ \#2\ Current\ Rating \cdot Array\ Voltage \cdot Power\ Factor \cdot \frac{(1-(Bury\ Depth\ -1)\cdot Bury\ Factor))}{1000}}\right) \tag{37}$$

Number of Turbines per Partial String: The model creates a partial string when the remainder of the number of turbines divided by the number of strings is greater than zero. The number of partial strings is always one, and the number of turbines that occupy the partial string is the remainder of the number of turbines divided by the number of full strings. The per-megawatt cost of the electrical and ancillary components is higher for a partial string than a full string because of the fewer number of turbines that occupy the partial string. This can create a minor spike in cost.

$$Remainder\left(\frac{Number\ of\ Turbines \cdot Turbine\ Rating}{\sqrt{3} \cdot Cable\ \#2\ Current\ Rating \cdot Array\ Voltage \cdot Power\ Factor \cdot \frac{(1-(Bury\ Depth\ -1)\cdot Bury\ Factor))}{1000}}\right) \tag{38}$$

Number of Turbines per Array Cable #1: Scaling relationship that determines the maximum amount of turbines that can be connected to the specified array cable #1. The relationship scales with the current rating for the selected array cable #1, the array cable system voltage, the power factor, the cable burial depth, the cable burial depth factor, and the turbine rating.

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$$\text{Round Down}\left(\frac{\sqrt{3}\cdot \text{Cable \#1 Current Rating}\cdot \text{Array Voltage}\cdot \text{Power Factor}\cdot \left(\frac{(1-(\text{Bury Depth }-1)\cdot \text{Bury Factor}))}{1000}\right)}{\text{Turbine Rating}}\right) \quad (39)$$

Number of Turbines per Array Cable #2: Scaling relationship that determines the maximum amount of turbines that can be connected to the specified array cable #2. The relationship scales with the current rating for the selected array cable #2, the array cable system voltage, the power factor, the cable burial depth, the cable burial depth factor, and the turbine rating.

$$\text{Round Down}\left(\frac{\sqrt{3}\cdot \text{Cable \#2 Current Rating}\cdot \text{Array Voltage}\cdot \text{Power Factor}\cdot \left(\frac{(1-(\text{Bury Depth }-1)\cdot \text{Bury Factor}))}{1000}\right)}{\text{Turbine Rating}}\right) \quad (40)$$

Number of Turbine Interfaces per Array Cable #1: Scaling relationship that scales with the number of turbines per array cable #1 and the number of strings. If a partial string is created, the relationship also scales with the number of turbines per partial string. Assumes two cable interfaces per turbine.

No Partial Strings:

$$(\text{Turbines on Cable \#1}\cdot \text{Full Strings})\cdot 2 \quad (41)$$

Partial String:

$$\left(\text{Turbines on Cable \#1}\cdot \text{Full Strings}+\min\left((\text{Turbines per Partial String}-1), \text{Turbines on Cable \#1}\right)\right)\cdot 2 \quad (42)$$

Number of Turbine Interfaces per Array Cable #2: Scaling relationship that scales with the number of turbines per array cable #2 and the number of strings. If a partial string is created, the relationship also scales with the number of turbines per partial string. Assumes two cable interfaces per turbine.

No Partial Strings:

$$Max1 = \max(\text{Turbines on Cable \#1} - \text{Turbines on Cable \#2}, 0) \quad (43)$$

$$Max2 = \max(\text{Turbines on Partial String} - \text{Turbines per Partial String}, 0) \quad (44)$$

$$(Max1\cdot \text{Full Strings} + Max2)\cdot 2 \quad (45)$$

Partial String:

$$Max1 = \max(\text{Turbines on Cable \#1} - \text{Turbines on Cable \#2}, 0) \quad (46)$$

$$Max2 = \max(\text{Turbines on Partial String} - \text{Turbines per Partial String}, 0) \quad (47)$$

$$(Max1\cdot \text{Full Strings} + Max2)\cdot 2 + 1 \quad (48)$$

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Number of Array Cable Substation Interfaces: Simple relationship that equates the number of strings to the number of array cable substation interfaces (because a group of turbines in a string share the same electrical line back to the offshore substation). Add one interface to account for a partial string.

No Partial String:

$$Substation\ Interfaces = Full\ Strings \tag{49}$$

Partial String:

$$Substation\ Interfaces = Full\ Strings + 1 \tag{50}$$

System Angle: System angle is a construct developed for this model to estimate the length of catenary, or free-hanging, electrical cables for floating wind power plants. Scales linearly with water depth. Calculated in degrees.

$$-0.0047 \cdot Water\ Depth + 18.743 \tag{51}$$

Free-Hanging Cable Length: The length of cable that hangs from a floating turbine substructure down to the seafloor with added length for abrasion protection. The length is estimated as the hypotenuse of a triangle using the system angle and the water depth as the length of the vertical leg. A length factor is multiplied by the hypotenuse length to account for the typical "S" curvature of the cable that is created using buoys and anchors during installation. Calculated in meters.

$$\left(\frac{Water\ Depth}{\cos(System\ Angle)}\right) \cdot (Catenary\ Length\ Factor + 1) + 190 \tag{52}$$

Fixed Cable Length: The length of the array cable that is fixed to the seafloor between the catenary cable sections between turbines. Calculated as the spacing between turbines along the string less the horizontal distances from the turbines to the cable touchdown points. The cable touchdown point is found using the system angle and the water depth to solve a right triangle to approximate the length from directly under the turbine along the seafloor to the cable touchdown point.

$$(Turbine\ Spacing \cdot Rotor\ Diameter) - (2 \cdot \tan(System\ Angle) \cdot Water\ Depth) - 70 \tag{53}$$

Array Cable #1 Length: The length of array cable #1 is calculated by an algorithm based on whether a fixed or a floating substructure type is selected. If a fixed substructure is selected, the length scales with the turbine spacing, the rotor diameter, the water depth, the number of turbine interfaces for array cable #1, and the excess cable factor. If a floating substructure is selected, the length scales with the fixed cable length, the free cable length, the number of turbine interfaces for array cable #1, and the excess cable factor.

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Fixed Substructure:

$$(Turbine\ Spacing \cdot Rotor\ Diameter + Water\ Depth \cdot 2) \cdot \left(\frac{Turbine\ Interfaces\ Cable\ \#1}{2}\right) \cdot (1 + Excess\ Cable\ Factor) \tag{54}$$

Floating Substructure:

$$(2 \cdot Free\ Cable\ Length + Fixed\ Cable\ Length) \cdot \left(\frac{Turbine\ Interfaces\ Cable\ \#1}{2}\right) \cdot (1 + Excess\ Cable\ Factor) \tag{55}$$

Array Cable #2 Length: The length of array cable #2is calculated by an algorithm based on whether a fixed or a floating substructure type is selected. If a fixed substructure is selected, the length scales with the turbine spacing, the rotor diameter, the water depth, the number of turbine interfaces for array cable #2, the spacing between strings, the number of strings including partial strings if any, and the excess cable factor. If a floating substructure is selected, the length scales with the fixed cable length, the free cable length, the number of turbine interfaces for array cable #2, the spacing between strings, the number of strings including partial strings if any, and the excess cable factor.

$$Max1 = \max(Turbines\ on\ Cable\ \#2 - 1, 0) \tag{56}$$

$$Max2 = \max(Turbines\ per\ Partial\ String - Turbines\ on\ Cable\ \#2 - 1, 0) \tag{57}$$

$$StrFac = \begin{cases} Partial\ Strings = 0, \dfrac{Full\ Strings}{Number\ of\ Substations} \\ Partial\ Strings = 1, \dfrac{Full\ Strings + 1}{Number\ of\ Substations} \end{cases} \tag{58}$$

Fixed Substructure:

$$\begin{aligned} &(Turbine\ Spacing \cdot Rotor\ Diameter + 2 \cdot Water\ Depth) \cdot (Max1 \cdot Full\ Strings + Max2) \\ &+ Number\ of\ substations \cdot (StrFac\ \cdot\ (Rotor\ Diameter \cdot String\ Spacing) \\ &+ \frac{\sqrt{\left((Rotor\ Diameter \cdot Turbine\ Spacing) \cdot (StrFac - 1)\right)^2 + (Rotor\ Diameter \cdot String\ Spacing)^2}}{2} \\ &+ StrFac \cdot Water\ Depth) \cdot (Excess\ Cable\ Factor + 1) \end{aligned} \tag{59}$$

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Floating Substructure:

$$\frac{(Fixed\ Cable + 2 \cdot Free\ Cable) \cdot (Max1 \cdot Full\ Strings + Max2) + Number\ of\ substations \cdot (StrFac \cdot (Rotor\ Diameter \cdot String\ Spacing)\ + \sqrt{((2 \cdot Free\ Cable) \cdot (StrFac - 1) + (Rotor\ Diameter \cdot String\ Spacing) - (2 \cdot \tan(System\ Angle) \cdot Water\ Depth) - 70)^2 + (Fixed\ Cable + 2 \cdot Free\ Cable)^2}}{2} \cdot (Excess\ Cable\ Factor + 1) \tag{60}$$

Array Cable #1 and Ancillary Cost: The array cable #1 cost is calculated by a simple relationship that scales with the cable #1 length and a per-meter cost rate. This is added to the ancillary cost, which scales with the number of turbine interfaces and a per-turbine-interface cost rate. If a floating substructure is selected, a dynamic cable factor is applied to account for the expected additional cost for cables made to withstand hanging slack in the ocean environment.

Fixed Substructure:

$$Cable\ \#1\ Length \cdot Cable\ \#1\ Cost\ Rate + \sum Turbine\ Interfaces \cdot Turbine\ Interface\ Cost \tag{61}$$

Floating Substructure:

$$(Cable\ \#1\ Length \cdot Cable\ \#1\ Cost\ Rate + \sum Turbine\ Interfaces \cdot Turbine\ Interface\ Cost) \cdot Dynamic\ Factor \tag{62}$$

Array Cable #2 and Ancillary Cost: The array cable #2 cost is calculated by a simple relationship that scales with the cable #2 length and a per-meter cost rate. This is added to the ancillary cost, which scales with the number of turbine interfaces, a per-turbine-interface cost rate, the number of substation interfaces, and a per-substation-interface cost rate. If a floating substructure is selected, a dynamic cable factor is applied to account for the expected additional cost for cables made to withstand hanging slack in the ocean environment.

Fixed Substructure:

$$Cable\ \#2\ Length \cdot Cable\ \#2\ Cost\ Rate + \sum Turbine\ Interfaces \cdot Turbine\ Interface\ Cost + \sum Substation\ Interfaces \cdot Substation\ Interface\ Cost \tag{63}$$

Floating Substructure:

$$(Cable\ \#2\ Length \cdot Cable\ \#2\ Cost\ Rate + \sum Turbine\ Interfaces \cdot Turbine\ Interface\ Cost + \sum Substation\ Interfaces \cdot Substation\ Interface\ Cost) \cdot Dynamic\ Factor \tag{64}$$

Number of Export Cables: The total number of export cables required to safely transfer the generated power to the onshore substation. The relationship scales with turbine rating, number of turbines, the export cable current rating, the export system voltage, the power factor, the cable burial depth, and the cable burial depth factor.

$$Round\ up\left(\frac{(Turbine\ Rating \cdot Number\ of\ Turbines)}{\sqrt{3} \cdot Current\ Rating \cdot Voltage \cdot Power\ Factor \cdot \frac{(1 - (Bury\ Depth - 1) \cdot Bury\ Factor)}{1000}}\right) \tag{65}$$

Export Cable Length: Calculated by an algorithm based on whether a fixed or floating substructure type is selected. If a fixed substructure is selected, the relationship scales with the

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distance to shore, the water depth, and the number of export cables. If a floating substructure is selected, it is assumed that a catenary section of cable hangs off of the offshore substation with a 500-m slack length for abrasion protection. The relationship scales with the distance to shore, the free cable length, and the number of export cables. Values calculated in meters.

Fixed Substructure:

$$(Distance\ to\ Shore \cdot 1000 + Water\ Depth) \cdot Number\ of\ Export\ Cables \cdot 1.1 \tag{66}$$

Floating Substructure:

$$(Distance\ to\ Shore \cdot 1000 + Free\ Cable\ + 500) \cdot Number\ of\ Export\ Cables \cdot 1.1 \tag{67}$$

Export Cable and Ancillary Cost: The export cable cost is calculated by a simple relationship that scales with the export cable length and a per-meter cost rate. This is added to the ancillary cost, which scales with the number of substation interfaces, and a per-substation-interface cost rate. If a floating substructure is selected, a dynamic cable factor is applied to the cable cost for only the section that hangs freely off of the substation to account for the expected additional cost for cables made to withstand hanging slack in the ocean environment.

Fixed Substructure:

$$Cable\ Length \cdot Cable\ Cost\ Rate + Number\ of\ Export\ Cables \cdot Substation\ Interface\ Cost \tag{68}$$

Floating Substructure:

$$Cable\ Cost\ Rate \cdot \big((Cable\ Length - Free\ Cable - 500) + Dynamic\ Factor(500 + Free\ Cable)\big) + Number\ of\ Export\ Cables \cdot Substation\ Interface\ Cost \tag{69}$$

Number of Substations: Simple relationship that scales with the number of export cables unless the number of export cables is less than two. Then the number of substations defaults to one.

$$\begin{cases} Export\ Cables \geq 2, & \dfrac{Export\ Cables}{2} \\ Export\ Cables < 2, & 1 \end{cases} \tag{70}$$

Number of Main Power Transformers (MPTs): Curve fit relationship, developed from available industry data, which scales with the number of turbines and the turbine rating.

$$Round\ up\left(\frac{Number\ of\ Turbines \cdot Turbine\ Rating}{250}\right) \tag{71}$$

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Single MPT Rating: Scaling relationship that scales with turbine rating, the number of turbines, and the number of MPTs. The relationship also has a condition that will round results up or down depending on the remainder of the calculated value. Values calculated in MVA.

$$\begin{cases} Remainder \geq 5,\ \ Round\ up\left(\frac{Number\ of\ Turbines \cdot Turbine\ Rating \cdot 1.15}{Number\ of\ MPTs}\right) \cdot \frac{1}{10} \\ Remainder < 5,\ \ Round\ down\left(\frac{Number\ of\ Turbines \cdot Turbine\ Rating \cdot 1.15}{Number\ of\ MPTs}\right) \cdot \frac{1}{10} \end{cases} \tag{72}$$

Total MPT Cost: Simple scaling relationship that scales with the single MPT rating, the number of MPTs, and a cost rate in dollars per MVA.

$$MPT\ Rating \cdot MPT\ Cost\ Rate \tag{73}$$

Switchgear Cost: Switchgear protects key electrical components and aids in voltage conversion. The cost is calculated using a simple relationship that scales with the number of MPTs and the sum of the high-voltage switchgear and medium-voltage switchgear fixed costs.

$$Number\ of\ MPTs \cdot (High\ Voltage\ Switchgear\ Cost + Medium\ Voltage\ Switchgear\ Cost) \tag{74}$$

Shunt Reactors Cost: Shunt reactors dissipate capacitive reactance generated by the power conversion and transfer systems within the offshore substation. The cost is calculated using a scaling relationship that scales with MPT rating, the number of MPTs, and a per-MVA cost rate.

$$MPT\ rating \cdot number\ of\ MPTs \cdot Shunt\ Reactor\ Cost\ Rate \cdot 0.5 \tag{75}$$

Ancillary Systems Cost: Ancillary systems are all components necessary to the proper function of the offshore substation, such as a backup generator and work and living space. The cost is calculated by the sum of fixed costs for the backup generator, the work and living space, and other aggregated ancillary costs.

$$Generator\ Cost + Workspace\ Cost + Other\ Ancillary\ Cost \tag{76}$$

Offshore Substation Topside Mass: The substation topside houses all electrical conversion and transmission components above the water line. Curve fit relationship developed from available industry data that scales with the MPT rating and the number of MPTs. Values calculated in tonnes.

$$3.85 \cdot (MPT\ Rating \cdot Number\ of\ MPTs) + 285 \tag{77}$$

Offshore Substation Topside Cost: Simple relationship scales with the substation topside mass, a fabrication cost rate per tonne, and a fixed design cost.

$$Substation\ Topside\ Mass \cdot Fabrication\ Cost\ Rate + Topside\ Design\ Cost \tag{78}$$

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Offshore Substation Topside Land Assembly Cost: Cost of assembling the substation on land before transporting it to the project site at sea. Values are calculated by multiplying an assembly scaling factor by the sum of costs for key substation components: switchgear, shunt reactors, and MPTs.

$$(Switchgear\ Cost + Shunt\ Reactor\ Cost + MPT\ Cost) \cdot Assembly\ Factor \tag{79}$$

Offshore Substation Substructure Mass: Calculated with an algorithm based on whether a fixed or a floating substructure type is selected. If a fixed substructure type is selected, then a curve fit scaling relationship that scales with the substation topside mass is used and the substructure type for the substation is modeled as a jacket lattice. If a floating substructure is selected, a semisubmersible substructure type is assumed. Scales with the total mass for a semisubmersible turbine substructure by a factor of two to account for the increased weight of the substation over the turbine. Values calculated in tonnes.

Floating Substructure:

$$2 \cdot (Semisubmersible\ Mass + Secondary\ Steel\ Mass) \tag{80}$$

Fixed Substructure:

$$0.4 \cdot Substation\ Topside\ Mass \tag{81}$$

Substation Substructure Pile Mass: Calculated with an algorithm based on whether a fixed or a floating substructure type is selected. If a fixed substructure type is selected, the substation will be installed onto a jacket lattice that requires piles driven into the seafloor to anchor the substructure. The mass of these piles is calculated using a curve fit relationship that scales with the substation fixed substructure mass. If a floating substructure is selected, the pile mass defaults to zero.

$$8 \cdot (Substation\ Substructure\ Mass)^{0.5574} \tag{82}$$

Offshore Substation Substructure Cost: Calculated with an algorithm based on whether a fixed or a floating substructure type is selected. If a fixed substructure is selected, the cost is the sum of the substation jacket mass and the pile mass multiplied by their respective cost rates per tonne. If a floating substructure is selected, the cost scales with the semisubmersible turbine substructure cost by a factor of two to account for the increased weight of the substation over the turbine.

Fixed Substructure:

$$Substation\ Substructure\ Mass \cdot Substation\ Substructure\ Cost\ Rate + Substation\ Pile\ Mass \cdot Substation\ Pile\ Cost\ Rate \tag{83}$$

Floating Substructure:

$$2 * (Semisubmersible\ Substructure\ Cost\ +\ Mooring\ System\ Cost) \tag{84}$$

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Onshore Substation Cost: Calculated via a curve fit relationship that scales with the grid interconnection voltage, the turbine rating, and the number of turbines. Costs calculated in dollars.

$$11652 \cdot (Interconnect\ Voltage + Turbine\ Rating \cdot Number\ of\ Turbines) + 1200000 \quad (85)$$

Onshore Substation Miscellaneous Costs: Curve fit relationship that scales with turbine rating and the number of turbines. Miscellaneous costs include cable termination and testing, cable pull-in, and ancillary costs.

$$11795 \cdot (Turbine\ Rating \cdot Number\ of\ Turbines)^{0.3549} + 350000 \quad (86)$$

Overhead Transmission Line Cost: The cost of the overhead transmission line that transfers the generated power to the electrical grid via a curve fit relationship that scales with the grid interconnect voltage and the distance to the grid interconnect from the onshore substation.

$$1176 \cdot Interconnect\ Voltage + 218257) \cdot (Distance\ to\ Interconnect)^{-0.1063} \cdot Distance\ to\ Inteconnect \quad (87)$$

Switchyard Cost: The cost of the switchyard, which plays a role in stepping up the voltage to the grid interconnect. Voltage is calculated via a curve fit relationship that scales with the interconnect voltage.

$$18115 \cdot Inteconnect\ Voltage + 165944 \quad (88)$$

Assembly and Installation

Mooring and Anchor Installation Time: The total time it takes to install and perform safety checks on the mooring and anchor systems for the entire wind power plant. Based on the type of anchor selected, the algorithm scales with a mooring time factor, the duration of equipment loadout, the number of mooring lines per substructure, the distance to the project site from the installation port, the install vessel transit speed, the number of turbines, and the substructure install weather contingency factor. Additional time is added for suction-pile-type anchors. Values calculated in days.

$$\big((Load\ Mooring + Place\ Anchors + \ Attach\ Lines) \cdot Number\ of\ Lines + Vessel\ Travel\ Time\big) \cdot (1 - Substurcture\ Contingency\ Factor) \quad (89)$$

Prepare Floating Substructure for Turbine Installation: The total time it takes to prepare floating substructures for installation of the turbine. For a spar substructure, this includes the time needed to prepare the inshore assembly area where the turbine installation will take place. The spar relationship scales with the time to prepare and upend the spar, the distance from the port to the assembly area, the vessel transit speed, the number of turbines, and the time needed to prepare the inshore assembly area. For a semisubmersible substructure, it is assumed that the turbine will be installed onto the substructure at the installation port; therefore, the corresponding relationship scales only with the number of turbines and the time required to prepare the substructure. Values calculated in days.

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Spar Substructure:

$$Round\ up\left((Prep\ Spar + Upend\ Spar) \cdot Number\ of\ Turbines\ + \frac{Distance\ Port\ to\ Assembly\ Area}{Vessel\ Transit\ Speed} + Prep\ Assembly\ Area\right) \tag{90}$$

Semisubmersible Substructure:

$$Round\ up(Prep\ Semisubmersible \cdot Number\ of\ Turbines) \tag{91}$$

Minimum Required Turbine Deck Area: The minimum deck area required per turbine for transport via vessel or barge. Based on which turbine installation method and which tower installation method are selected, the algorithm calculates the area using the component dimensions and the specified inspection clearance. Values calculated in square meters.

$$\sum(Component\ Area + \ Inspection\ Clearance) \tag{92}$$

Turbines per Vessel Trip: The maximum number of turbines per trip that can be transported to the project site from the installation port. The algorithm calculates according to the substructure type and the installation vessel strategy. For fixed substructure types, the number of turbines per trip depends on either the maximum payload or the available deck space, whichever is the limiting factor based on the turbine and vessel or barge specifications. For spar substructures, a similar approach is taken though components are ferried to the installation area by barges which typically have lower maximum payloads and available deck space than primary installation vessels. For semisubmersible substructures, it is assumed that the turbine is installed at port and then towed to the project site, so a value of one is always assumed for turbines per trip.

$$\min\left(\left(\frac{Available\ Deck\ Space}{Deck\ Space\ per\ Turbine}\right), \left(\frac{Max\ Payload}{Total\ Turbine\ Mass}\right)\right) \tag{93}$$

Minimum Required Substructure Deck Area: The minimum deck area required per substructure for transport via vessel or barge. Depending on the substructure, the area is calculated using the specified substructure's dimensions and the specified inspection clearance. Floating substructures are assumed to be towed by tug and not transported by vessel or barge, so the minimum deck area required defaults to zero and is not used in calculations for floating substructures. Values calculated in square meters.

$$\sum(Component\ Area + \ Inspection\ Clearance) \tag{94}$$

Substructures per Vessel Trip: The maximum number of substructures that can be transported via the selected vessel. For fixed substructures, this number depends on the available deck space or the maximum payload of the selected vessel or barge, whichever becomes the limiting factor depending on the substructure and vessel specifications. Floating substructures are assumed to be towed by tug and not transported by vessel or barge, so the substructures per trip defaults to zero and is not used in calculations for floating substructures.

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$$\min\left(\left(\frac{Available\ Deck\ Space}{Deck\ Space\ per\ Substructure}\right),\left(\frac{Max\ Payload}{Total\ Substructure\ Mass}\right)\right) \quad (95)$$

Turbine Installation Time: The total time required to install all turbines that make up the wind power plant. The turbine installation time depends on the turbine and tower installation methods, the type of substructure, and the installation vessel strategy. Each substructure has its own installation assumptions for turbine installation. For fixed substructures under the primary vessel strategy, an installation vessel will make trips to the project site carrying turbine components. The installation vessel will be positioned near the preinstalled substructures, and the turbine will be assembled on the substructure. For fixed substructures under the feeder barge strategy, an installation vessel remains at the project site for turbine installation while tugs and barges ferry components to the project site from port. For spar substructures, the turbine components are towed by barge to an inshore assembly area where the spar is upended and the turbine is installed. The assembled turbine and spar are then towed to the project site where the mooring and anchor lines are attached and surveyed. For semisubmersible substructures, the turbine is installed onto the semisubmersible at port, and then the assembled turbine and semisubmersible are towed to the project site where the mooring and anchor lines are attached and surveyed. Various timing values and factors are applied to estimate the duration of each process based on user-defined selections and specifications. Values calculated in days.

$$(Load\ Turbine + Assemble\ Turbine + Vessel\ Travel\ Time + Vessel\ Positioning) \cdot (1 - Turbine\ Contingency\ Factor) \quad (96)$$

Substructure Install Time: The total time required to install all substructures that will support the turbines making up the wind power plant. The substructure installation time depends on the type of substructure and the installation vessel strategy. Each substructure has its own installation assumptions. For fixed substructures under the primary vessel strategy, an installation vessel will make trips carrying substructures to the project site where it will be positioned near the substructure locations and substructure installation will proceed. For fixed substructures under the feeder barge strategy, an installation vessel remains at the project site for substructure installation while tugs and barges ferry substructures to the project site from port. For floating substructures, the substructure installation time includes the mooring and anchor installation time and the time required to prepare the floating substructure for turbine installation. There are various timing values and factors that are applied to estimate the duration of each process based on the user-defined selections and specifications. Values calculated in days.

Fixed Substructure:

$$(Load\ Substructure + Vessel\ Travel\ Time + Vessel\ Positioning + Prepare\ Equipment + Install\ Substructure) \cdot (1 - Substructure\ Contingency\ Factor) \quad (97)$$

Floating Substructure:

$$Mooring\ Install\ Time + Substructure\ Prep\ Time \quad (98)$$

Array Cable #1 Section Mass: The mass of the cable sections for array cable #1 that will make up the array electrical connections. For example, a section is the length of cable between two

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turbines. The cable section mass depends on the section length and the mass per-unit length of the cable that is selected for the array cable #1. Values calculated in tonnes.

$$(Cable\ \#1\ Mass \cdot Section\ Length) \cdot \frac{1 + Excess\ Cable\ Factor}{1000} \tag{99}$$

Array Cable #2 Section Mass: The mass of the cable sections for array cable #2 that will make up the array electrical connections. An example of a section would be the length of cable between two turbines. The cable section mass depends on the section length and the mass per-unit length of the cable that is selected for the array cable #2. Values calculated in tonnes.

$$(Cable\ \#2\ Mass \cdot Section\ Length) \cdot \frac{1 + Excess\ Cable\ Factor}{1000} \tag{100}$$

Array Cable #1 Sections per Vessel Trip: The maximum number of array cable #1 sections that can fit onto an array-cable-laying vessel per trip to the project site. The number of cable sections depends on the cable section mass and the mass capacity of the cable carousel of the selected vessel.

$$Round\ down \left(\frac{Vessel\ Cable\ Carousel\ Capacity}{Cable\ \#1\ Section\ Mass}\right) \tag{101}$$

Array Cable #2 Sections per Vessel Trip: The maximum number of array cable #2 sections that can fit onto an array-cable-laying vessel per trip to the project site. The number of cable sections depends on the cable section mass and the mass capacity of the cable carousel of the selected array-cable-laying vessel.

$$Round\ down \left(\frac{Vessel\ Cable\ Carousel\ Capacity}{Cable\ \#2\ Section\ Mass}\right) \tag{102}$$

Array Cable Install Time: The total time required to install the array cable system and any ancillary components. The duration depends on the cable sections per trip for array cable #1 and #2, the length of both array cables, the number of strings, the number of turbine interfaces, the number of substation interfaces, the number of turbines per partial string, the number of turbines per cable, the excess cable factor, the distance to port, the vessel transit speed, the cable bury rate, the time required to make and check electrical connections, the time required to load cable sections at port, and the electrical installation weather contingency factor. Values calculated in days.

$$(Load\ Cables + Surface\ Lay\ Cables + Bury\ Cables + Vessel\ Travel\ Time + Make\ Connections) \cdot (1 - Electrical\ Contingency\ Factor) \tag{103}$$

Export Cable Section Mass: The mass of the export cable section that connects to the offshore substation and terminates at the onshore substation. The section mass depends on the length of the export cable and the mass per-unit length of the cable that is selected for the export cable. Values calculated in tonnes.

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$$\frac{Cable\ Mass \cdot Cable\ Length}{Number\ of\ Export\ Cables} \cdot 1000 \tag{104}$$

Number of Export Cable Sections per Vessel Trip: The maximum number of export cable sections that can fit onto an export-cable-laying vessel per trip to the project site. The number of cable sections depends on the cable section mass and the mass capacity of the cable carousel of the selected export-cable-laying vessel.

$$\frac{Vessel\ Cable\ Carousel\ Capacity}{Export\ Cable\ Section\ Mass} \tag{105}$$

Export Cable Installation Time: The total time required to install the export cable and ancillary components. The duration depends on the number of export cables, the length of the export cables, the number of export cables per vessel trip, the vessel transit speed, the time required to load cables onto the vessel at port, the distance to shore, the distance to the project site from port, the time required to make and check electrical connections, and the electrical installation weather contingency factor. Values calculated in days.

$$(Load\ Cables + Surface\ Lay\ Cables + Bury\ Cables + Vessel\ Travel\ Time + Make\ Connections) \cdot (1 - Electrical\ Contingency\ Factor) \tag{106}$$

Offshore Substation Installation Time: The total time required to install the offshore substation. The algorithm calculates according to whether a fixed or a floating substructure is selected. If a fixed substructure is selected, the relationship depends on the time required for the substation loadout at port, the distance from port to the project site, the time needed to position the vessel, the time to place and secure the topside to the foundation, and the electrical installation weather contingency factor. For floating substructures, the substation is installed onto a semisubmersible platform and then towed to the project site. In this case, the relationship depends on the time needed to place and secure the topside to the substructure, prepare the assembly for towing, the distance from the port to the project site, the vessel tow speed, the time required to position the vessel and substructure, the time required to attach and survey the mooring connections, and the electrical installation weather contingency factor. Values calculated in days.

$$Round\ up((Load\ Substation + Vessel\ Travel\ Time + Vessel\ Positioning + Place\ Topside) \cdot (1 - Electrical\ Contingency\ Factor)) \tag{107}$$

Turbine Install Cost: The total cost of installing all of the turbines that make up the wind power plant. A simple relationship that scales with the turbine installation time, the type and number of vessels, and the vessel and equipment day rates.

$$\sum (Day\ Rate \cdot Turbine\ Install\ Time) \tag{108}$$

Substructure Installation Cost: The total cost of installing all of the substructures that support the turbines that make up the wind power plant. A simple relationship that scales with the substructure installation time, the type and number of vessels, and the vessel and equipment day rates.

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$$\sum(Day\ Rate \cdot Substructure\ Install\ Time) \tag{109}$$

Electrical Infrastructure Installation Cost: The total cost of installing the complete electrical system that delivers the generated power to the grid. A simple relationship that scales with the array cable install time, the export cable install time, the offshore substation installation time, the duration and cost of installing the onshore infrastructure, the type and number of vessels, and the vessel and equipment day rates.

$$\sum(Day\ Rate \cdot Electrical\ System\ Install\ Time) \tag{110}$$

Vessel Mobilization and Demobilization Cost: The total cost of mobilizing and demobilizing the entire spread of vessels and equipment required for installation of the wind power plant. A simple relationship that scales with the time required to mobilize and demobilize, the type and number of vessels, and the vessel and equipment day rates.

$$\sum(Day\ Rate \cdot Mobilization\ Time \cdot Install\ Seasons) \tag{111}$$

Port and Staging

Port Entrance and Exit Cost: The cost of entering and exiting the installation port via vessel during installation operations. The relationship depends on the substructure type, the vessel footprint area, the number of occurrences, and a rate charged per square meter of vessel area per occurrence.

$$Vessel\ Footprint\ Area \cdot Occurrences \cdot Entrance\ Cost\ Rate \tag{112}$$

Docking Cost: The total cost of docking the installation vessel at the installation port for the duration of the wind power plant installation. A simple relationship that scales with the total install time and the docking day rate.

$$Total\ Install\ Time \cdot Docking\ Day\ Rate \tag{113}$$

Wharf Cost: The cost of the wharf where components will be loaded and unloaded to and from vessels at the installation port. A simple relationship that scales with the total weight of the components being loaded and unloaded including all turbine and substructure components and a wharf rate per tonne of mass.

$$Total\ Component\ Mass \cdot Wharf\ Rate \tag{114}$$

Substructure Laydown Area: The area required area for laydown and storage of substructure components at the installation port during installation operations. The algorithm calculates according to whether a fixed or floating substructure type is selected. If a fixed substructure is selected, the relationship scales with the substructure dimensions, the specified inspection clearance, and the number of substructures stored at the port. The number of substructures stored at the port is assumed to be twice as many as the number of substructures that can fit onto the installation vessel or feeder barge so that there are always substructures available at the port to be

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loaded for transport to the project site. For floating substructures, there is no requirement for laydown and storage at the installation port because it is assumed that floating substructures will be floated and towed from the manufacturer to the installation sites. Values calculated in square meters.

$$Deck\ Area\ per\ Substruture \cdot Substuctures\ per\ Trip \cdot 2 \tag{115}$$

Substructure Laydown Cost: The cost of the laydown and storage of substructures at the installation port. A simple relationship that scales with the substructure laydown area and a cost rate per square meter of laydown area. No cost is assumed for floating substructures.

$$Substurcture\ Laydown\ Area \cdot Laydown\ Rate \tag{116}$$

Turbine Laydown Area: The area required for the laydown and storage of turbine components at the installation port during installation operations. The relationship scales with the turbine component dimensions and the required inspection clearance. This value then scales with twice the number of turbines that can fit onto the installation vessel or feeder barge so that there are always turbines ready to be loaded for transport to the project site. Values calculated in square meters.

$$Deck\ Area\ per\ Turbine \cdot Turbines\ per\ Trip \cdot 2 \tag{117}$$

Turbine Laydown Cost: A simple relationship that multiplies the turbine laydown area by the laydown cost rate per unit area.

$$Turbine\ Laydown\ Area \cdot Laydown\ Rate \tag{118}$$

Crane Cost: Determined by a simple relationship that scales with the total installation time, the number of cranes, crane day rates, and the crane mobilization and demobilization cost. The cranes used during installation are assumed to be used for the entire duration of the installation.

$$Number\ of\ Cranes \cdot Crane\ Day\ Rate + Crane\ Mobilization\ Cost \tag{119}$$

Engineering and Management

Total Engineering and Management Cost: Determined by a simple relationship that scales with the total hard costs, which include all costs related to procurement and installation of components, and an estimated engineering and management cost factor.

$$\sum (Hard\ Costs) \cdot Estimated\ E\ \&\ M\ Factor \tag{120}$$

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Development

Front-End Engineering Design (FEED) Cost: The cost of the initial design and planning processes that occur during early-stage development of the proposed wind power plant. Calculated as a sum of inputs for the pre-FEED and FEED studies, which are performed by design engineers and financial analysts.

$$FEED\ cost + preFEED\ Cost \tag{121}$$

Permitting, Studies, and Compliance Costs: All costs associated with obtaining legal approval of the proposed wind power plant project. Calculated as the sum of the inputs for permitting, studies, and compliance costs.

$$\sum (Permits\ and\ Compliance\ Costs) \tag{122}$$

Meteorological (Met) Tower Fabrication and Installation Cost: The total cost of fabricating and installing a met tower at the proposed project site. The met tower is used to obtain wind resource data, weather data, and various other data that are used for approval and verification of the proposed project site. Calculated as a function of turbine rating, the number of turbines, and a met tower cost rate per MW of installed capacity. The curve fit relationship was developed using available data from BOEM.

$$Number\ of\ Turbines \cdot Turbine\ Rating \cdot Met\ Tower\ Cost\ Rate \tag{123}$$

Decommissioning Expense: The expected decommissioning cost of the wind plant is calculated as a percentage of the installation cost broken down by activity type, such as turbine installation. Based on the assumption that decommissioning the wind power plant will be very similar to the installation process, but in reverse. Calculated in the future value and then discounted back to present dollars via a decommissioning discount rate.

$$\frac{\left(\Sigma\left(\frac{Install\ Time \cdot Estimated\ Decommissioning\ Factor}{Total\ Install\ Time}\right) \cdot Total\ Install\ Cost - Scrap\ Value\ \right)}{(1 + Discount\ Rate)^{Project\ Life}} \tag{124}$$

Plant Commissioning: The total cost of commissioning activities required to bring the wind power plant online. These activities include testing and verifying power transfer and redundancy systems, as well as ensuring the generated power is compatible with and transferable to the electrical grid. Estimated as a percent of total CapEx including the turbine.

$$\sum (CapEx) \cdot Plant\ Commissioning\ Cost\ Factor \tag{125}$$

This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.