Offshore Wind Balance-of-System Cost Modeling

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Introduction

Table 1. Baseline Parameters (Fixed/Floating)

Project Size (megawatts [MW])	600
Turbine Rating (MW)	6
Rotor Diameter (meters [m])	155
Hub Height (m)	90
Distance to Shore (kilometers [km])	40
Distance to Installation Port (km)	60
Water Depth (m)	25/250
Array Spacing (rotor diameters)	9x9

Offshore wind balance-of-system (BOS) costs contribute up to 70% of installed capital costs. 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. As a result, the National Renewable Energy Laboratory (NREL) developed and recently updated a BOS techno-economic model using project cost estimates created from wind energy industry sources.

Updates to the model help analyze both fixed and floating substructure types. Other updates include a subsea cable cost optimizer and improved scaling relationships. Figure 1 and Figure 2 show the BOS cost breakdown by category for fixed and floating substructures, respectively. Electrical infrastructure, substructure and foundation, and assembly and installation categories dominate BOS costs for both substructures.

NREL performed analyses using common baseline parameters (Table 1) to see what effect(s) changing one variable at a time would have on BOS costs. The results of this analysis are meant to demonstrate the capabilities of the offshore BOS model rather than to compare fixed versus floating substructures. The results of these analyses should be taken as representative only, because of the high level of variability of project parameters and site-specific elements.

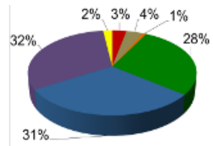


Figure 1. BOS cost breakdown (fixed substructure)

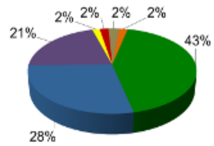
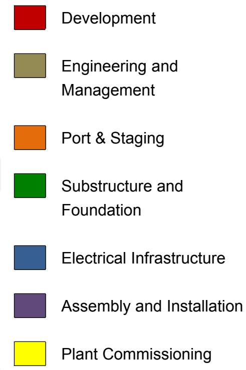


Figure 2. BOS cost breakdown (floating substructure)



Wind Plant Sensitivities

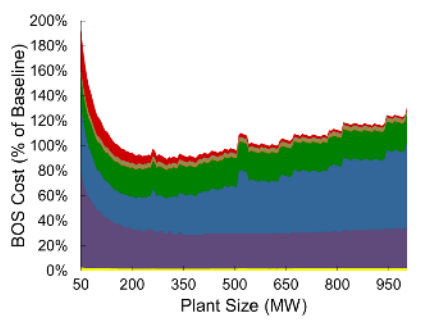


Figure 3. Sensitivity to plant size

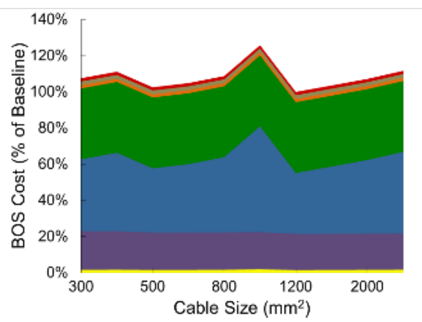


Figure 6. Sensitivity to export cable size

Fixed Substructure Sensitivities

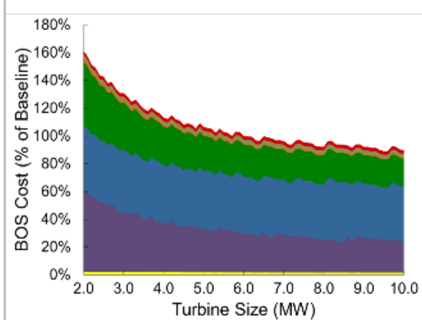


Figure 4. Sensitivity to turbine size

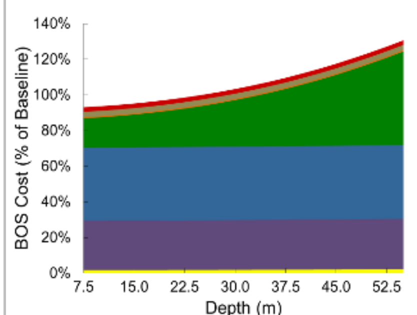


Figure 7. Sensitivity to water depth

Floating Substructure Sensitivities

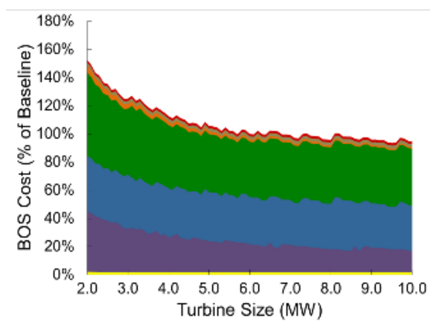


Figure 5. Sensitivity to turbine size

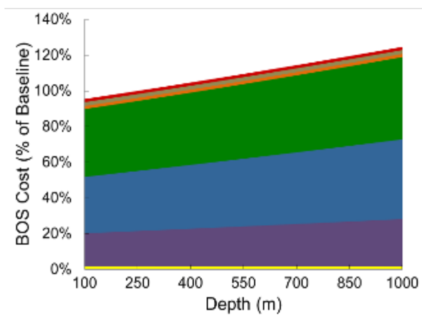


Figure 8. Sensitivity to water depth

Conclusions

Figure 3. Fixed BOS costs distributed over more megawatts results in a decrease in cost per megawatt-hour to a point. Eventually a steady increase in cost is caused by overestimated cable lengths connecting turbines to the offshore substation because arrays are modeled in a rectangular grid layout and only one offshore substation is assumed for all plant sizes. The saw tooth shape is a result of how turbines are located within strings. Sharp cost increases happen when a new string of turbines is created that contains only one turbine and as more turbines fill this string costs decrease until a new string is needed. The larger, less frequent sharp changes in cost result from the model optimizing, for lowest cost, array and export cable size selection (including installation cost). Spikes in cost are a result from the model selecting array and export cables that are capable of safely transferring generated power at the lowest cost, which, depending on input parameters, can yield a rise in BOS cost, such as the spike near 500 megawatts.

Figure 4. Offshore wind fixed substructure BOS costs decrease as turbine rating increases, which is largely driven by the reduction in installation time required because fewer turbines are needed to achieve the same plant capacity. The jagged shape of the graph is also a result of how turbines are located within strings and how the model optimizes for lowest cost cable size selection (including installation cost).

Figure 5. Offshore wind floating substructure BOS costs also decrease with increasing turbine size primarily because of reduced installation time. The cost decrease is more gradual than fixed substructures because floating substructure and foundation costs are more dependent on turbine size. The increase in substructure costs slightly offsets the cost savings from the use of fewer turbines and a shorter installation time.

Figure 6. Export cable costs are driven primarily by the minimum amount of export cables required to safely transfer the power generated by the wind plant to the land-based substation. For example, three 1,000 square millimeter (mm^2) cables are necessary to transfer the same power as two 1,200 mm^2 cables. The 1,200 mm^2 cable is more expensive per meter of cable length than the 1,000 mm^2 cable, but the total export cable length is much greater when more cables are required. Thus, the total installed capital cost is greater for the smaller 1,000 mm^2 cable size in this case. This tradeoff between cable size and the number of cables required is represented in the figure by the large peak followed by a reduction in total capital cost as the cable size switches from 1,000 mm^2 to 1,200 mm^2.

Figure 7. As the water depth increases so does the offshore wind BOS cost. This effect is mainly driven by the substructure and foundation cost, which increases because of the need for larger, more robust support structures in deeper waters. The overall BOS cost rises faster than for floating substructures because of increased depth for fixed substructures; the economic viability of fixed substructures is more dependent on water depth than floating substructures.

Figure 8. Offshore wind BOS costs increase with deeper water. The floating bottom relationship is relatively linear and primarily driven by electrical infrastructure and assembly and installation costs rather than foundation costs. The escalation in foundation component costs like mooring lines, which must expand in length with deeper water, is relatively small compared to the rise in cost from electrical components and assembly and installation.

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