A Low-Cost Modular Concrete Support Structure and Heavy-Lift Vessel Alternative: Final Project Report

Final Report

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Table of Contents

Notice i

Preferred Citation i

Acknowledgments ii

List of Figures v

List of Tables v

Acronyms and Abbreviations vi

Summary 1

1 Conceptual Design and Cost Estimating of a 15-MW Modular Concrete Support Structure 1

1.1 Scale Up RCAM's 10-MW Modular Concrete Support Structure Concept to 15 MW 1

1.2 Estimate Hydrodynamic and Aerodynamic Loads on the Modular Concrete Support Structure for a 15-MW Reference Turbine 5

1.3 Determine the Approximate Suction Pile Size, Spacing, and Cost 8

1.4 Advance the Conceptual Design(s) for the Modular Concrete Support Structure 12

1.5 Identify the Support Structure Assembly Process, and Estimate Production Rate and Costs 16

1.6 Update the Product Development Project Plan and Assess Organizational Strength 20

2 Assess Technical Feasibility of Support Structure Transportation and Installation Concepts 22

2.1 Feasibility Assessment of Transport and Installation Systems for the 15-MW Modular Suction Pile Support Structure Using Auxiliary Floatation and Telescoping Tower Systems 22

2.2 Estimate Costs for Transporting, Wet Towing, and Installing the Reference and Modular Foundations 24

3 Develop Reference Model and Perform Levelized Cost of Energy Analyses 28

3.1 Perform Levelized Cost of Energy Analysis 28

4 Stakeholder/Advisory Panel Down-Selection Workshop 31

5 Identify Northeastern Reference Sites for Manufacturing, Assembly, and Installation 33

6 Preliminary Design of Modular Support Structure and Transportation and Installation Systems 36

6.1 Update Metocean Loads Based On Down-Selected Support Structure Design and Northeastern Reference Site 36

6.2 Analyze Seakeeping During Transport and Assembly 37

6.3 Update the Transportation and Installation System Conceptual Design and Cost Estimates 39

6.4 Conceptual Design Alternative of 3DCP Legs and Suction Buckets 40

6.5 Concrete Support Structure Assembly Process and Estimates of Production Rate and Costs 42

6.6 Update CapEx and LCOE Estimates 44

6.7 Regional Economic Benefits Analysis 46

7 Plan Follow-On Structural Testing, Field Demonstration, and Certification Activities 49

7.1 Update the Risk Assessment 49

7.2 Laboratory Testing and Future Research and Development Planning 50

7.3 Utility-Scale Pilot Test Planning 51

7.4 Plan Commercialization 54

8 Stakeholder/Advisory Panel Comprehensive Workshop 58

9 References 60

List of Figures

Figure 1. Sketch of foundation with dimensional parameters 4
Figure 2. Representative time-series data for hydrodynamic loading on substructure 7
Figure 3. Penetration plots for the penetration—Caisson A (in sand) 12
Figure 4. Telescoping tower for 6-MW wind turbine for the ELICAN Project....... 15
Figure 5. Concept Option 1: Concrete tilt slab construction methodology....... 17
Figure 6. Concept Option 2: Traditional forming system with match casting process 18
Figure 7. Jones Act deck barge with pin connection-transport configuration overview 23
Figure 8. Option 2: Suction bucket substructure wet tow and installation 25
Figure 9. Average installation costs compared to the average installation time for the foundation and turbine installation phases in each of the scenarios 29
Figure 10. Two-site scenario: Separate marshalling site 34
Figure 11. Barge plus jack-up legs solution 38
Figure 12. Monte Carlo simulation results showing the ranges or probable cost outcomes derived from the probabilistic estimate 43
Figure 13. Total employment impact in the United States per $10 million of foundation spending, by foundation type 48

List of Tables

Table 1. Wave base shear and overturning moment for some of the studied turbine ratings, water depths, and shaft sizes 3
Table 2. Comparison of base shear and bending moments at two stations (0 m and −50 m mean sea level [MSL]) as calculated by scaling laws and the HydroDyn software 8
Table 3: Preliminary suction caisson characteristics....... 10
Table 4: Suction caisson penetration results....... 11
Table 5. Phase I cost summary table comparing cost per 15-MW wind turbine for the monopile foundation as compared with the fixed-bottom concrete tripod foundation concept 20
Table 6. Required marine equipment for the various phases of the transportation and installation processes 26
Table 7. Sectional loads for Task 1.4 and Task 6.1 37

Acronyms and Abbreviations

ACI	American Concrete Institute
API	American Petroleum Institute
BOEM	Bureau of Ocean Energy Management
CapEx	capital expenditures
DLC	design load case
DNV	Det Norske Veritas
DOE	U.S. Department of Energy
DP	dynamic positioning
IEA Wind	International Energy Agency Wind Technology Collaboration Programme
IEC	International Electrotechnical Commission
ISO	International Organization for Standardization
IPS	Independent Pontoon System
LCOE	levelized cost of energy
ORBIT	Offshore Renewables Balance-of-system Installation Tool
NYSERDA	New York State Energy Research and Development Authority
3DCP	three-dimensional concrete printing
RRD	Rick Damiani Engineering, LLC
TRL	technology readiness level
UNL	University of Nebraska–Lincoln
ULS	ultimate limit state
WTIV	wind turbine installation vessel

Summary

The majority of U.S. offshore wind energy capacity additions during the next decade will be located along the Eastern Seaboard on fixed-bottom support structures. However, the newly emerging East Coast offshore industry faces numerous cost, production rate, and environmental challenges associated with conventional support structures. The project goal is to prove the feasibility for and advance the development of a low-cost, modular concrete suction pile support structure and heavy-lift vessel alternative. The multiphase project scope spans two funding categories. The Category A (Feasibility Study) portion of the project includes the conceptual design and feasibility assessment of a modular concrete support structure for a 15-MW reference wind turbine and heavy-lift vessel alternative. The Category B (Product Development) portion of the project includes down-selection of a support structure, preliminary design of the modular concrete support structure, and planning of potential follow-on activities such as fabrication, structural testing, and pilot demonstration.

S.1 Conceptual Design and Cost Estimation of a Modular Concrete Support Structure for a 15-MW Reference Wind Turbine

Task 1 aimed to advance the conceptual design and estimate the costs of RCAM's modular precast concrete support structure concept. The support structure was designed for the National Renewable Energy Laboratory's (NREL's) 15-MW reference wind turbine and an installation site 50 m to 60 m deep. The project team estimated the aerodynamic and hydrodynamic loads on the modular concrete support structure, performed a study of suction pile size and cost, sized the support structure concrete modules, and estimated the support structure production rate and costs. The following were major outcomes of Task 1:

- Several modular concrete design alternatives were developed that were concluded to be technically feasible.
- Three-dimensional concrete printing (3DCP) was identified as an emerging technology with the potential to cost-effectively manufacture substructure components and increase the production rate. This outcome informed later project efforts to create a conceptual design and manufacturing and assembly processes using 3DCP and compare them to conventional modular construction.
- The substructure's overall capital expenditures (CapEx) has been identified as the most considerable nontechnical risk and the most important cost reduction opportunity.

S.2 Technical Feasibility of Support Structure Transportation and Installation Concepts

In Task 2, the project team focused on (1) assessing the technical feasibility of wet towing and installing the support structure and wind turbine at the installation site in different levels of assembly and (2) estimating the costs to transport the modular support structure to the marshaling site and the installation site in different assembly configurations. The team examined the risks, challenges, practicality, and benefits of using auxiliary flotation or telescoping tower systems to wet tow and install RCAM's modular concrete support structure with the turbine fully assembled and without heavy-lift wind turbine installation vessels. The following were key outcomes from Task 2:

- Three transportation and installation concepts were initially validated that would allow transportation and installation of the modular concrete support structure with the wind turbine fully assembled and without a heavy-lift wind turbine installation vessel, reducing installation costs and decreasing installation duration from over 8 months to 4 months.
- The structure's stability during the submersion and installation process was identified as the most substantial technical risk for the project. To address this risk, new towing and installation concepts were identified during Phase I and evaluated further in Phase II.

S.3 Reference Model Development and Levelized Cost of Energy Analyses

In Task 3, the project team performed a preliminary comparative assessment of three levelized cost of energy (LCOE) scenarios for a 1,005-MW wind plant comprising sixty-seven 15-MW wind turbines using different foundations. NREL evaluated LCOE using the Offshore Renewables Balance-of-system Installation Tool (ORBIT). Three scenarios were compared: (1) a conventional monopile installed using a wind turbine installation vessel (WTIV) with a feeder barge, (2) a concrete tripod that is installed using tugboats and other low-cost vessels followed by a WTIV that assembles the turbines on top of the installed tripod, and (3) a concrete tripod and turbine that are assembled at quayside, then wet towed and installed at the site using tugboats, thus circumventing the need for a WTIV. The following were key outcomes for Task 3:

- Shifting from a conventional monopile strategy to the concrete tripod with coupled turbine installation substantially reduces the installation costs, from $118.90/kW to $8.90/kW. In absolute terms, this is equivalent to a reduction from $119 million to $9 million for a 1,005-MW plant. This is achieved not only by eliminating the expensive WTIV from the installation vessel spread but also by decreasing the installation time from 257 days to 130 days.
- Deceases in installation cost only minimally influence the overall CapEx and LCOE because installation costs are small compared to the cost of each turbine and foundation. The LCOE of the tripod was similar to that of the monopiles: $74.80/MWh for the monopile to $74.90/MWh for the sequential tripod and $74.50/MWh for the coupled tripod. Within precision of this type of study, the LCOE costs for the two foundations are about the same.

- The concrete tripod foundation, relative to the monopile, alleviates risks and challenges associated with the scarcity of WTIVs in the global market, long monopile installation timelines, dependency on a European supply chain, and environmental impacts of monopile installation.

S.4 Stakeholder/Advisory Panel Down-Selection Workshop

The project team held a stakeholder/advisory group workshop to review and obtain stakeholder feedback on the results of recently completed Phase I tasks and revised Phase II workplan. There appeared to be more interest in the deployment of fully assembled wind turbines and heavy-lift vessel alternatives than originally thought at the start of the project. It was noted that installation solutions that are relatively simple, quick, and low risk appeared to be some of the most important criteria to stakeholders. Alternative anchor solutions to suction buckets, such as traditional piles, also appeared to be of interest to stakeholders and could address a primary and common stakeholder concern that suction buckets do not work everywhere. Based on the workshop outcomes, the project team decided to also consider concepts that allow for the potential use of driven piles and even gravity bases as "preinstalled" foundations that could be used as the foundation for the tripod.

S.5 Identification of Northeastern Reference Sites for Manufacturing, Assembly, and Installation

In Task 5, WSP assessed sites in the northeastern United States for their potential to host manufacturing, assembly, and launching of the modular concrete support structure. WSP developed a set of search criteria for fabrication, assembly, and marshaling sites and outlined several scenarios based on different combinations of sites. Four sites along the northeast coast of the United States were noted as feasible marshaling sites for this project with unrestricted air draft and sufficient channel width to tow the concrete support structure with mounted turbines. The marshaling sites could potentially host co-located fabrication of foundation components, or substructure components could be manufactured at more remote sites and barged or towed as needed.

The team concluded that the manufacturing, assembly, and deployment of the modular support structure technology is feasible in the Bureau of Ocean Energy Management (BOEM) call areas of the East Coast. The report identified eight scenarios with sites that could host major fabrication and assembly of the concrete modular foundation. The sites are in states that could potentially be an offtaker to expected wind developments in water depths of 50 m (164 ft) or greater, including Massachusetts, Connecticut, Rhode Island, and New York. All the selected facilities at these sites either already exist or are in planning stages. Once fully developed, all are expected to meet the search criteria with only modest project-specific improvement needs.

These findings supported the project team's hypothesis that a variety of suitable facilities and associated supply chain facilities exist or are in development near expected future offshore wind plants that are well suited for manufacturing and assembling concrete support structures.

S.6 Preliminary Design of Modular Support Structure and Transportation and Installation Systems

Task 6 aimed to increase the fidelity of the support structure design and transportation and installation systems based on learnings from Phase I. Task 6 also included the conceptual design and analysis of 3DCP manufacturing for the support structure concept. First, the hydrodynamic loads on the support structure were updated using an analysis of the actual foundation geometry rather than a simplified monopile-type assumption. Next, NETSCo advanced the seakeeping analysis of RCAM's fixed-bottom tripod substructure deployed with the fully assembled wind turbine, and down-selected an auxiliary stability system with support from the project team that included a flotation aid. The project team invented a novel flotation system to address the risks of stability during support structure installation and estimated its costs. Using the updated loads, WSP developed the conceptual design of the support structure considering both conventional concrete construction and 3D concrete printing. The project team then updated manufacturing cost estimates and LCOE estimates and performed an analysis of economic benefits. The following were key findings of Task 6:

- The newly developed flotation aid system became a strong area of emphasis for the project, as it addressed stakeholder input and furthered the project goals of developing a heavy-lift vessel alternative that is fully scalable to future larger wind turbines and substructures.
- The conceptual design work produced designs for the tripod foundation that are manufacturable using conventional concrete construction. Design for 3DCP components in the tripod indicated the potential to use 3DCP to optimize the structure with more complex geometries that reduce hydrostatic pressure and can reduce steel reinforcement content in key areas, providing potential cost savings.
- An updated probabilistic manufacturing cost estimate indicated a median cost scenario of $9.6 million per turbine ($638/kW) for the tripod compared to a monopile cost of $6.3 million per turbine ($423/kW). A sensitivity analysis indicated that labor costs have the greatest impact on the overall variability of the forecasted final foundation cost, and the tripod hub piece had the greatest construction complexity.
- The updated LCOE value of $76.70/MWh is 3% higher than the monopile cost for the specific site considered. The LCOEs for the monopile and tripod are considered to be about the same considering the precision of this type of study. The installation costs of the concrete tripod are

still significantly lower than the monopile scenario, as no WTIV is required, which helps to offset the higher capital cost of the structure. Most of the cost differential was due to the higher CapEx of the concrete foundation.

- While concrete foundations cost more than monopile foundations, on a national level, the concrete tripod foundation results in more than 3 times the number of jobs resulting from largely imported steel monopiles per unit cost. Increased economic benefits and other non-LCOE benefits of the proposed solution, such as accelerating installation timelines and alleviating WTIV limitations, hold potential competitive advantages against monopiles.

S.7 Planned Follow-On Structural Testing, Field Demonstration, and Certification Activities

Task 7 planned follow-on testing, demonstration, and certification activities required for commercialization of the modular concrete support structure and heavy-lift vessel alternative system. The major steps included updating the risk assessment (Subtask 7.1), creating preliminary test plans and estimating the costs for laboratory structural tests (Subtask 7.2), and full-scale demonstration planning (Subtask 7.3).

RCAM updated a risk assessment framework to inform future testing and demonstration activities. By addressing uncertainties, the framework increased the likelihood of successfully developing RCAM's offshore wind turbine support structure. The most important risks were those associated with launching, marshaling, transporting, and installing the foundation, especially relating to seakeeping and stability during installation. Using 3DCP to manufacture the foundation will create additional construction methodology risks and uncertainties associated with 3DCP's lower technology readiness level. The project team defined testing programs to address the most critical structural risks, including validating the performance of the connections between the support structure and the suction buckets, validating the failure behavior of the buckets, testing wall joint water tightness, and testing a model of the entire substructure in a wave tank to validate hydrodynamic computer modeling of the force levels and scour behavior under various sea states. Scale tank/basin testing of a model structure was planned, including static tests, a dynamic tow test, wave testing, wind-scale testing, and installation simulation. A full-scale (15-MW to 20-MW) pilot testing program of the substructure and flotation aids was designed. Planned pilot testing includes incline testing, ballasting and de-ballasting, and jacking system testing. Manufacturing testing would include testing of lifting lug designs and hoisting/rigging, which can be completed during the full-scale fabrication of the pilot prototype.

RCAM is pursuing a commercialization plan that develops and demonstrates its modular concrete support structure and heavy-lift vessel alternative at full scale (15-MW-class turbines) in 2028. RCAM projects an additional approximately $67 million of funding will be required to bring the foundation and Independent Pontoon System (IPS, RCAM's proprietary flotation aid) to technology readiness level 7.

RCAM's funding strategy uses nondilutive state and federal funding for early stages of development, followed by larger private investments from strategic partners. $5.1 million of investments are required for the detailed design, structural testing of the foundation, and wave basin testing of the IPS. Approximately $20.3 million is required to develop a full-scale IPS system which is substantially less than the approximately $500M required to develop a wind turbine installation vessel (Parkison and Kempton 2022). RCAM plans to further explore a multiuse approach for the IPS to leverage this investment.

RCAM will continue to develop its 3DCP approach for concrete anchors and energy storage systems. The approach will create new cost-reduction opportunities for the foundation prototype, which will reduce the cost of commercialization by approximately $20 million by eliminating the formwork required for the first prototype, reduce port footprint, automate construction, and leverage equipment and capabilities developed for RCAM's other offshore wind and energy products. In addition, 3DCP is projected to reduce the cost of each foundation by half a million dollars during commercial production.

S.8 Stakeholder/Advisory Panel Comprehensive Workshop

RCAM held a stakeholder/advisory panel comprehensive workshop on March 3, 2022, to obtain stakeholder and subject matter expert feedback on the results of the Phase I and Phase II project tasks. The workshop successfully communicated the project results to over 36 project stakeholders and potential commercialization partners. The following summarizes the most important feedback from the workshop:

- There was agreement that the WTIV bottleneck is still a major concern due to limited vessel availability in the United States.
- Marshaling port space in the United States is also a major concern, with reports indicating an insufficiency of available or planned marshaling areas to support U.S. offshore wind energy targets.
- The fully assembled deployment configuration was identified as an attractive solution.
- 3D concrete printing can help address U.S. port footprint constraints (Parkison and Kempton 2022) and substructure geometry changes.

These outcomes indicated the potential value of the tripod foundation solution in terms of alleviating vessel bottlenecks and providing greater economic benefits.

1 Conceptual Design and Cost Estimating of a 15-MW Modular Concrete Support Structure

The design objective is to develop a low-cost offshore wind turbine foundation made of concrete anchored to the sea floor by suction buckets for a typical offshore wind development with 750-MW to 1,500-MW nameplate capacity. Task 1 aimed to advance the conceptual design and estimate the costs of RCAM's modular precast concrete support structure concept. The support structure was designed for the International Energy Agency's 15-MW reference wind turbine and an installation site 50 m to 60 m deep. The project team estimated the aerodynamic and hydrodynamic loads on the modular concrete support structure, performed a sensitivity study of suction pile size and cost, sized the support structure concrete modules, and estimated the support structure production rate and costs.

1.1 Scale Up RCAM's 10-MW Modular Concrete Support Structure Concept to 15 MW

In Subtask 1.1, the project team scaled an RCAM tripod concrete foundation previously designed for a 10-MW wind turbine in 30-m water depth to a 15-MW turbine in 50-m and 60-m water depths. Four different design configurations were analyzed: (1) deployment with turbine and without specialized vessel or temporary stabilization, (2) deployment of floating foundation with turbine and without specialized vessel, but with temporary stabilization during tow and installation, (3) deployment of floating foundation only and installation of turbine offshore, and (4) deployment with installation vessel (nonfloating option).

The original foundation concept was a 10-MW turbine at a hub height of 125.5 m in a 30-m water depth, described in the final technical report of a previously completed RCAM Phase I Small Business Technology Transfer project funded by the U.S. Department of Energy (DOE). The first step was to scale the support structure design for the newly available International Energy Agency Wind Technology Collaboration Programme (IEA Wind) 15-MW offshore wind reference turbine to make the project results more relevant to planned commercial deployments (Gaertner et al. 2020). The foundation design is driven by a myriad of factors spanning the entire life cycle from fabrication to decommissioning. Besides construction cost and schedule, the most influential criteria for the foundation features are related to overturning moment from wind and floating stability during tow and installation. One of the largest potential cost savings is in the selection of methods and equipment required for transportation and installation. A key decision is whether to make the foundation self-floating for transportation, deployment, and installation or to use specialized equipment and vessels to stabilize the wet towing of the foundation and assist during installation.

Four different alternative deployment methods were evaluated for the 15-MW turbine in a 50-m water depth:

1. **Fully assembled/self-floating: Design for floating stability for full deployment with turbine**. Foundation with turbine to be designed to float at acceptable draft and stability throughout tow and submersion.
2. **Fully assembled/auxiliary flotation: Design for floating stability for full deployment with turbine with means of additional stabilization**. Foundation with turbine to be designed to float at acceptable draft and stability throughout tow and submersion with the aid of auxiliary flotation and/or telescoping tower technology.
3. **Foundation only/self-floating: Design for floating stability for full deployment of foundation only**. Foundation to be designed to float at acceptable draft and stability throughout tow and submersion. Installation of turbine at offshore site.
4. **Foundation only/nonfloating: Design for vessel deployment**. Foundation provides minimum buoyancy and no floating stability and needs to be transported and installed with a shear crane barge or a skid-launch barge with crane. Tower and turbine will have to be installed offshore with means of a jack-up barge.

The design criteria include a maximum draft of 12.2 m, which allows the foundation to be towable in typical deep-water ports. A maximum design wind speed of 16 m/s was selected as typical for wind turbine installation.

The foundation was conceptually designed for the governing load cases and design criteria. The conceptual design check demonstrated that the concrete meets allowable stress levels under operational wind and wave loads only. Characteristic concrete properties were assumed to be representative of a concrete with 60 MPa compressive strength. Because the 15-MW IEA Wind reference turbine loads were still in development and not yet available to the project team, the aerodynamic and wave forces from the 10-MW wind turbine listed in RCAM's Small Business Technology Transfer final report and computed by NREL were scaled using simplified scaling factors to define the loads for the 15-MW turbine for the conceptual design. The study focused only on Design Load Case (DLC) 6.1 derived by NREL for extreme sea state (significant wave height of 9.81 m and significant wave period = 13 s) in combination with a parked turbine at extreme winds (70 m/s) with an occurrence interval of 50 years. The turbine and tower weight were scaled proportional to the turbine nameplate capacity. The dynamic wind loads on the turbine were scaled proportional to the turbine nameplate capacity. The wave loads were assumed to be proportional to the square of the diameter of the shaft, assuming inertial forces are more dominant than drag forces and the water can flow around the shaft. The assumptions did not consider that wave loads decrease for deeper water. The resulting scaled loads for selected shaft sizes are summarized in Table 1.

Table 1. Wave base shear and overturning moment for some of the studied turbine ratings, water depths, and shaft sizes

Design Criteria	10-MW Turbine 30-m Water Depth	15-MW Turbine 30-m Water Depth	15-MW Turbine 50-m Water Depth	15-MW Turbine 60-m Water Depth
Average Submerged Shaft Diameter	8.54 m	13.4 m	16.6 m	16.5 m
Base Shear from Waves	10.1 MN	25 MN	43.2 MN	45.2 MN
Overturning Moment from Waves	193 MN·m	478 MN·m	919 MN·m	1,140 MN·m

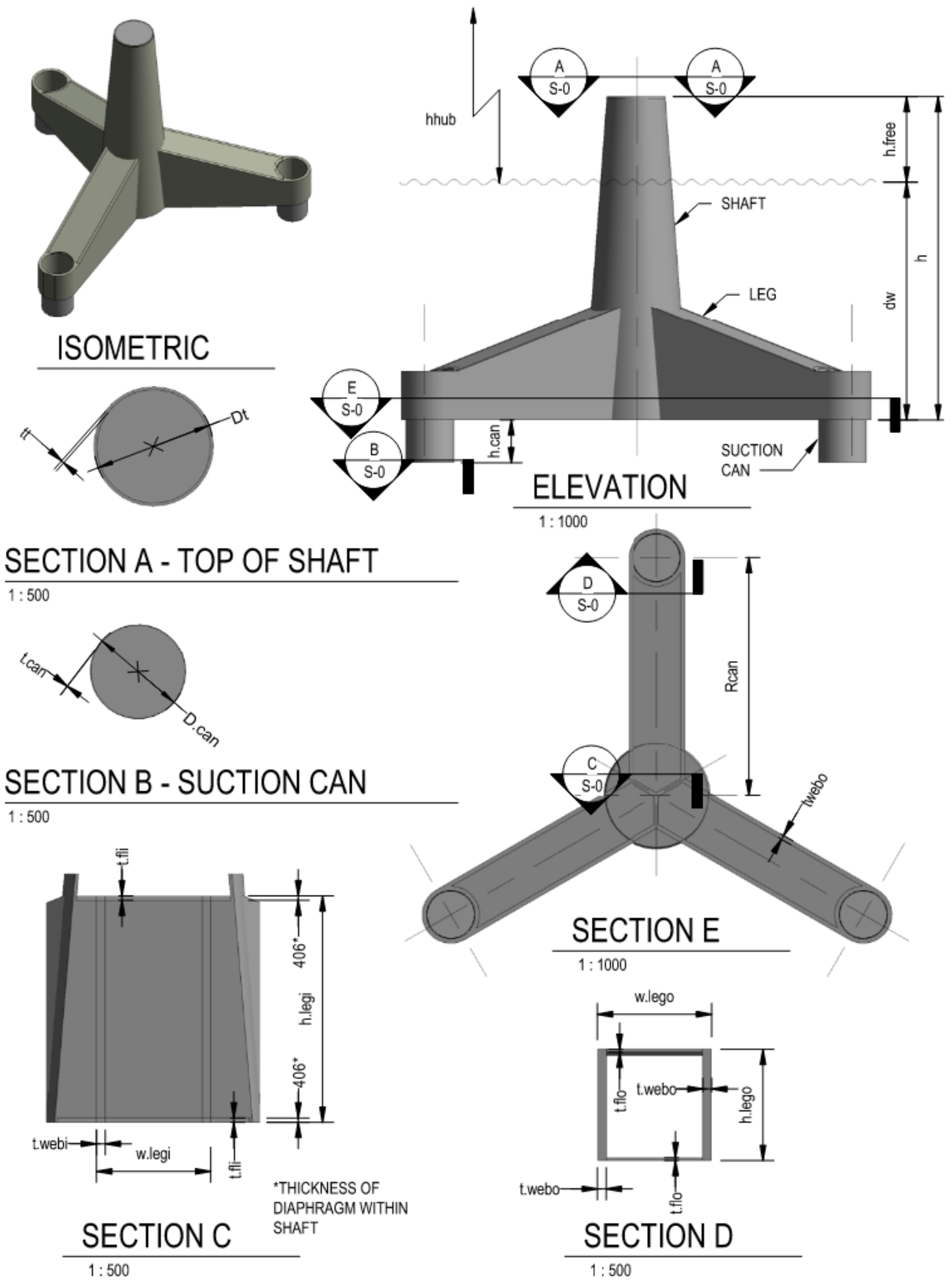
A parameter study based on simple linear-elastic beam theory was performed to estimate the stress states in the shaft and legs. The legs were chosen to be hollow, watertight box-beams to provide maximum buoyancy. The design was subjected to an optimization calculation performed in Mathcad to minimize the overall foundation weight while still meeting the design constraints and conceptual design criteria. The parameter study was conducted for four different design alternatives with different base radii and number of legs. The calculations identified three different optimized foundation geometries for the 50-m water depth that could meet the design criteria.

Figure 1 shows a sketch of the dimensional parameters for a floating foundation option with a 50-m radius. The preliminary results suggest that all the considered design alternatives are technically feasible, potentially cost-effective, and warrant further design and analysis. The cost-efficiency of the different design alternatives depends on project-specific parameters such as the location of the wind farm; the availability of concrete fabrication facilities, marshaling facilities, and specialized equipment; and the project schedule. For the 60-m water depth, only the first design alternative (independent floating foundation with turbine) was evaluated to prove the scalability of the concept.

Figure 1. Sketch of foundation with dimensional parameters

This sketch is representative of the foundation option with a 50-m radius and independent floating concept.

Source: WSP USA



Next, three construction methodologies were assessed: precast concrete, cast-in-place construction using slip forming or jump forming, and three-dimensional concrete printing (3DCP). For a typical offshore wind farm of 750 MW to 1,500 MW, 50 to 100 foundations will have to be produced at a rate of at least one or two foundations per week once the first foundation is launched. At a mass of 12,500 tons per foundation, this results in a concrete production rate of 1,750 to 3,500 tons per day, or the equivalent of 50 to 100 large, fully loaded concrete mix trucks. Precast and cast-in-place construction are established approaches that benefit from a high level of structure modularization to create equal or similar components that are built in "production lines" and then assembled to final structures. 3D concrete printing is an emerging technology that has the potential to cost-effectively manufacture substructure components, including the suction buckets, legs, hub, pedestal, and potentially even the tower if desired. However, significant research and testing are required prior to commercialization.

1.2 Estimate Hydrodynamic and Aerodynamic Loads on the Modular Concrete Support Structure for a 15-MW Reference Turbine

In Subtask 1.2, RRD Engineering, LLC (RRD) performed a more detailed analysis of the simplified load scaling that was carried out in Subtask 1.1. In particular, the hydrodynamic loading had to be verified to facilitate further detailed conceptual design. The simplified aerodynamic loads analysis was deemed to be sufficient for the preliminary level of design at this early stage in the project. RRD also gathered the meteorological ocean (metocean) and turbine data needed for the current and future modeling tasks.

The substructure was modeled as an equivalent monopile clamped at the seabed with a length of 68 m (freeboard 18 m). The assumed global coordinate system has origin at (0,0,0 m mean sea level) with the x-axis along the mean wind direction and the z-axis pointing up. Metocean conditions were provided by NREL for a generic site along the Eastern Seaboard, including significant wave heights and peak spectral periods as a function of wind speed at hub height for normal sea state conditions. For the extreme wave data, however, the initial data were incomplete and yielded unrealistic values. Upon consultation among all team members, NREL provided a revised table of extreme events. Based on estimates from assurance and risk management firm Det Norske Veritas (DNV) and standards from the American Petroleum Institute (API) and the International Organization for Standardization (ISO) (specifically, API RP 2MET 2nd edition and ISO 19901-1:2015), the deck-height elevation was selected as 18 m. The splash zone was calculated as per DNV standards.

An analysis was conducted for the ultimate limit state (ULS) loads only to verify the simple scaling done in Subtask 1. RRD also assembled a fully aero-hydro-servo-elastic model for further processing when the stiffness of the substructure becomes available. Given the uncertainties on the geometry and the complexity of the fatigue treatment for precast concrete structures, fatigue limit states were not considered in this phase of the project. One ULS load case was selected, loosely exemplifying International Electrotechnical Commission (IEC) standard 61400-3-1:2019 DLC 6.1a (IEC 2019). HydroDyn (the OpenFAST hydrodynamics module) was exercised in stand-alone fashion (i.e., the substructure was considered rigid, and no turbine effect was included). The focus of this deliverable was on the hydrodynamics loading alone. The turbine loads were scaled from those available in a previous study on a 10-MW turbine.

DLC 6.1a is a parked case, characterized by extreme wind and wave conditions, whereas IEC 61400-3 calls for multiple misaligned wind and wave directions to be analyzed under DLC 6.1a. The current was removed to facilitate a comparison with scaled loads from Subtask 1.1. Wind and wave directions were kept along the same direction to increase conservatism.

The wind loads on the exposed portion of the substructure were calculated assuming a simple distributed drag force, with a two-dimensional drag coefficient in air for the cylindrical stem equal to 0.7. The wind speed at each stem section was calculated using a wind shear exponent of 0.11. The loads from the turbine were ignored in this calculation.

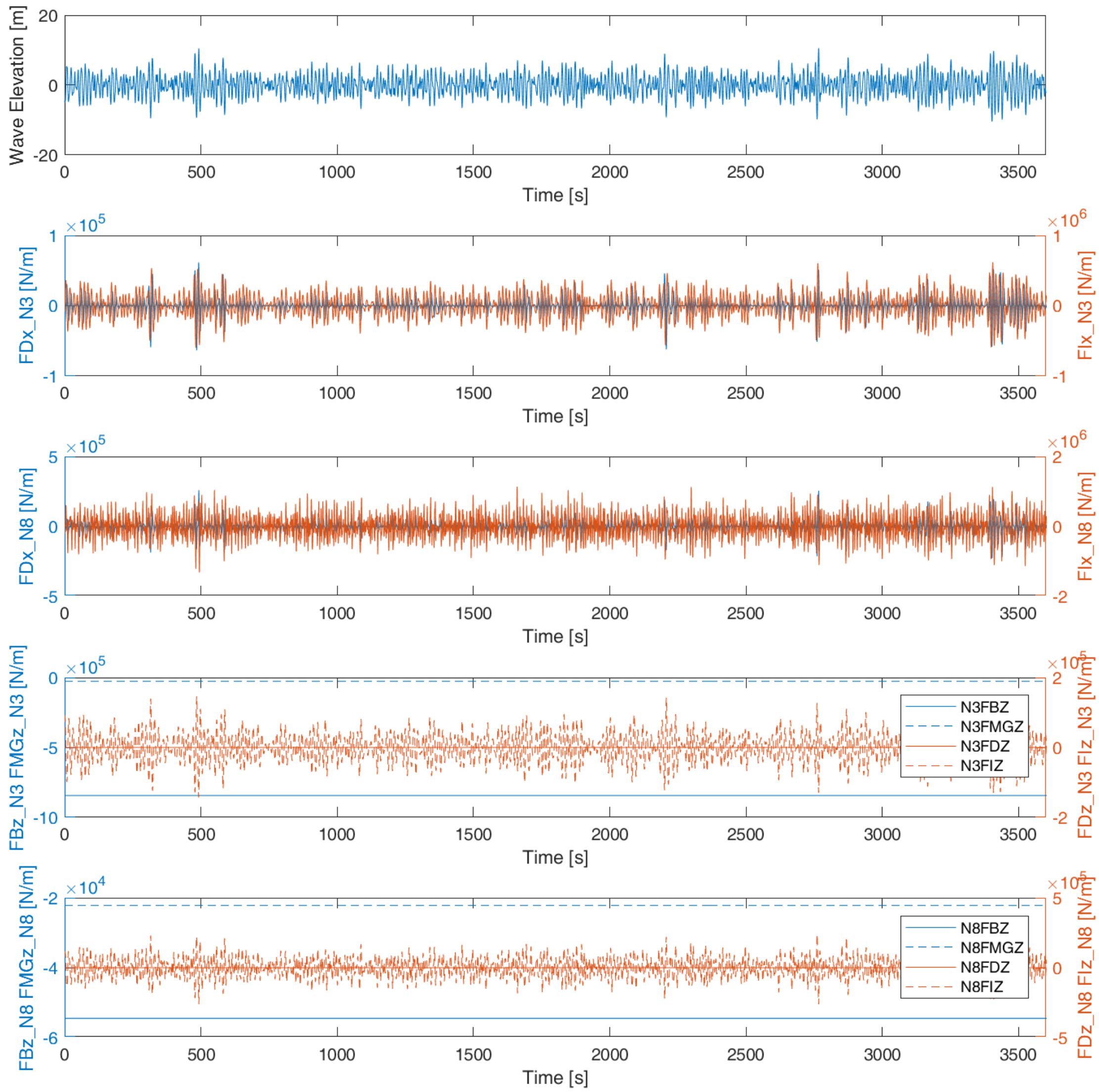
HydroDyn was the main software used to calculate the hydrodynamic loads on the substructure. For these calculations, HydroDyn was run in stand-alone mode, ignoring the small kinematics of the structure itself and any structural response. A strip-theory solution was selected and validated for the structure geometry and wave regimes assumed. Waves were assumed to be short crested with wave energy spread across directions ±45° to the mean (0°) wind direction. No wave stretching or higher-order wave theories were used. Second-order hydrodynamics was not deemed necessary, as it mostly pertains to floating structure response. The simulation time was set at 3,600 s to guarantee a stochastically well-developed sea state.

The loads calculated by HydroDyn were time series of distributed external loads (N/m) derived from the resulting hydrostatic and hydrodynamic pressures and viscous stresses. Nine stations (HydroDyn nodes) were selected along the span of the stem to report the distributed loads. Figure 2 shows examples of the calculated hydro-load components (drag, inertial, buoyancy, and marine growth gravitational components) at Nodes 3 and 8 for the DLC of interest.

Figure 2. Representative time-series data for hydrodynamic loading on substructure

The data include wave elevation, drag (FD_x) and inertia (FI_x) forces along global x-axis, drag (FD_z) and inertia (FI_z) forces along global z-axis (axial direction), buoyancy (FB_z) and marine growth gravitational (FMG_z) forces at Node 3 (N3) and Node 8 (N8).

Source: RRD Engineering, LLC



The peak values (maxima and minima) of the hydrodynamic loads were stored for the nine stations and integrated in postprocessing and converted to internal loads. As an additional level of conservatism, the maximum (and minimum) loads at different sections were considered to occur simultaneously (which, however, was the case for most stations). Table 2 shows the results from Deliverable 1.1 compared to those from the HydroDyn calculations. Deliverable 1.1 employed first-principal scaling laws to arrive at shear (along the inertial x-axis) and bending moments (about the inertial y-axis). The loads in Deliverable 1.1 were generally overestimated and thus were conservative. The errors in the load components calculated at the seabed are acceptable, and therefore the sizing conducted in Deliverable 1.1 is assumed valid for this phase of the project. The errors pertinent to the mean sea level station are quite large. However, these loads do not account for the contribution of the turbine thrust and other aerodynamic loads and will change significantly when the fully coupled analysis is run. Therefore, the noted discrepancies are not a cause of concern at this stage in the project.

Table 2. Comparison of base shear and bending moments at two stations (0 m and −50 m mean sea level [MSL]) as calculated by scaling laws and the HydroDyn software

Load Component	Scaling (Deliverable 1.1)	HydroDyn Stand-Alone Results	Relative Error [%]
Tx @ z = 0 MSL [kN]	5.598e3	1.98e3	183
Tx @ −50m [kN]	4.32e4	3.364e4	28
My @ MSL [MN·m]	44.251	3.9	1035
My @ z = −50m [MN·m]	919.1	907.5	1

1.3 Determine the Approximate Suction Pile Size, Spacing, and Cost

Subtask 1.3 was performed by subcontractor Cathie Associates. The scope of this subtask was to perform (1) a preliminary suction caisson tripod foundation design including approximate suction caisson size, spacing, and cost for the reference turbine needed to resist the hydrodynamic and aerodynamic loads computed in Deliverable 1.2, and (2) a preliminary suction-caisson installation assessment examining the allowable installation and extraction pressures and highlighting any significant risk to operations.

The suction caisson design was undertaken according to Carbon Trust and DNV recommendations for the specified ground conditions and using the loads detailed in Deliverable 1.1. Based on discussions with the consortium team, RCAM selected the Wilmington Canyon Project site as the reference site for the assessment in Phase I of the project. Conditions at this site were described by Kempton et al 2017. Two main soil units were identified within the probable foundation depth: Unit 1 – medium to very dense sand, medium grains, with limited coarse fraction (gravel, cobbles, and boulders), and Unit 2 – medium- to high-strength silty clay, medium plasticity. Geotechnical properties were estimated based on the soil unit descriptions and regional experience. Lower bound/best estimate and upper bound profiles are of most interest to the foundation engineering. Profiles aligned with lower bound/best estimate are considered likely and are thus mostly used in capacity analyses. Upper bound profiles are considered in most installation analyses according to a conservative approach. Preliminary caisson dimensions were used as the basis for optimization.

Appropriate partial load factors were considered in the analyses at the ULS, as per DNV standards DNV-ST-0437 and DNVGL-OS-C101. The caissons need to be designed to provide sufficient capacity for the factored design loads. The total loads experienced by the tripod structure were detailed in Deliverable 1.4. A preliminary load redistribution analysis was then conducted to derive the single-caisson (factored) loads starting from the total loads at the tripod structure, as detailed in Deliverable 1.4.

The direction of the environmental load leads to the maximum compression or tension regime of the caisson of interest. Load cases considered include (1) structure self-weight only, (2) environmental loading (at 180° direction) with minimum self-weight load, maximum tension on Caisson 1, and (3) metocean loading (at 0° direction) with maximum self-weight load, maximum compression on Caisson 1.

The suction caisson in-place capacity was assessed according to Carbon Trust and DNV recommendations. The ULS holding capacity of suction caissons was determined by assessing the maximum vertical and horizontal capacities separately and then determining a failure envelope for the combined loading regime. The capacity calculation methods used were in line with those detailed in the Carbon Trust suction caisson design guidelines (Cathie et al. 2019).

The resulting preliminary suction caisson sizing is summarized in Table 3. The conceptual-level design indicates that the suction caissons would provide a suitable foundation for the tripod structure, with sufficient holding capacity to resist to ULS load. For the smaller Caisson A in sands, the uplift regime is the most critical condition; by removing the tension component by adding ballast in the substructure, a reduction in caisson size to approximately 10 m in diameter and 10.5 m in penetrated length could be achieved. Additional reduction of the required caisson size may be achieved by accounting for the contact area of the underside of the tripod structure, designing a hybrid gravity-suction tripod structure. For the larger Caisson B in sands over clay, the compressive regime governs the at-failure design.

Table 3: Preliminary suction caisson characteristics

Parameter	Dimension	
	Caisson A (Sand)	Caisson B (Sand over Clay)
Caisson Outside Diameter	11.0 m	13.0 m
Caisson Inside Diameter	10.9 m	12.9 m
Wall Thickness	50 mm	50 mm
Skirt Length	11.5 m	11.5 m
Embedment	11.5 m	11.5 m
Caisson Submerged Weight*	124 Te (metric ton)	147 Te
Critical Load Case	Tension	Compression

* Assumed fully flooded members for estimation of buoyancy.

The approach for installation resistance is based on the latest information available in the Carbon Trust design guidelines (Cathie et al. 2019). The resistance to penetration comprises the skin friction along the sides of the caisson and the end bearing capacity of the caisson, as detailed by (DNV 2021). The key drivers of the design are (1) prediction of the vertical penetration resulting from the self-weight of the structure only and (2) estimation of the response of the soils when subject to suction pressures, resulting in predicted depth of penetration. Limiting factors are applied such as hatch size and penetration speed, piping failure (in sands), and plug uplift failure (in clays).

Installation analyses were undertaken for the lower bound and upper bound soil parameters. Figure 3 shows plots of penetration resistance and required installation pressure for Caisson A. The required installation pressure and hatch flow rates are within reasonable ranges.

Table 4: Suction caisson penetration results

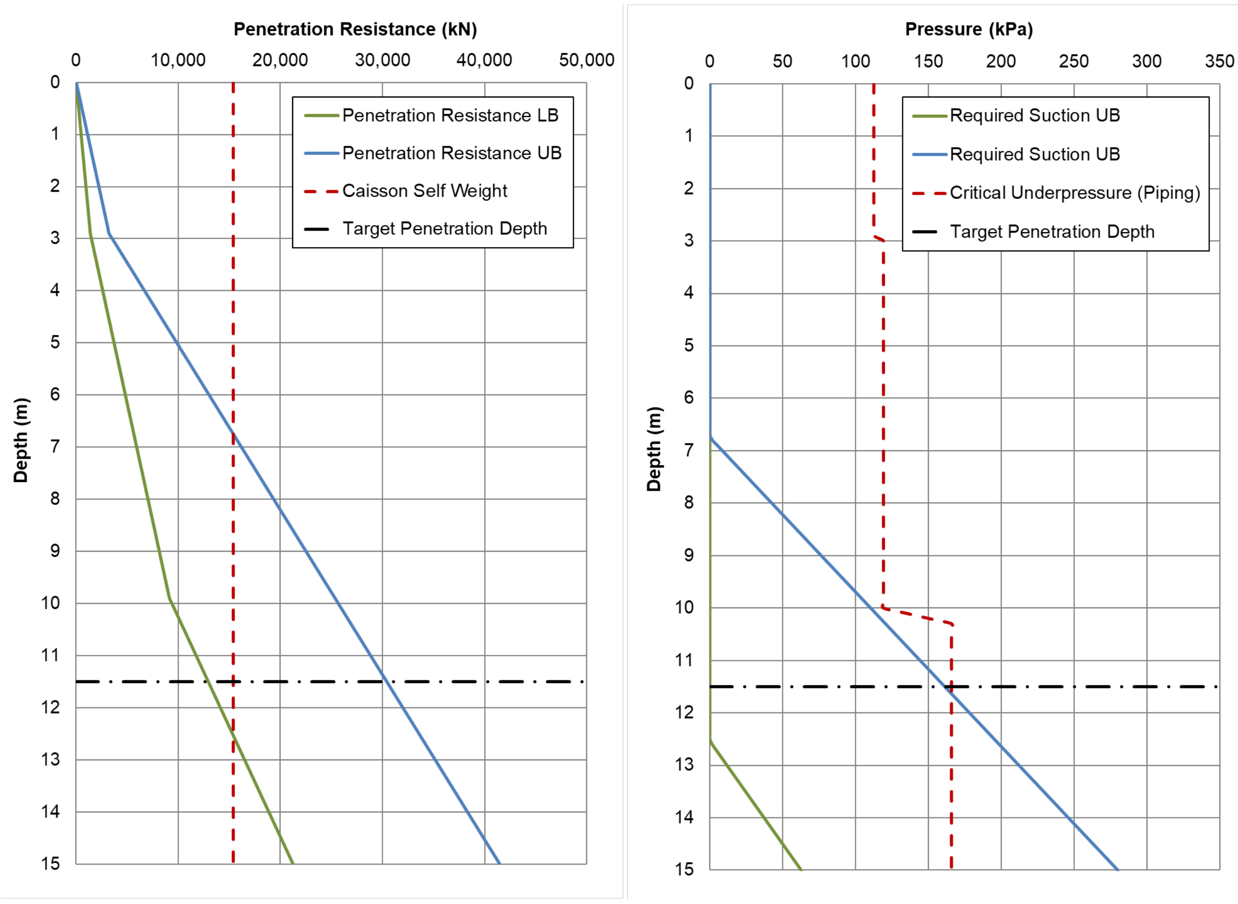
Penetration Assessment		Caisson A (in sand)		Caisson B (in sand over clay)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Assumed installation weight [Te]		1,568		1,591	
Self-weight penetration depth [m]		12.5	6.7	12.3	6.3
Maximum required underpressure [kPa]		0	161	0	112
Soil plug heave limiting pressure (clay)	**Maximum allowable underpressure [kPa]**	–	–	673	1,050
	Factored allowable underpressure [kPa]	–	–	449	700
Piping failure limiting pressure (sand)	**Factored allowable underpressure [kPa]**	166		–	

The results indicate that installation via simple (controlled) self-weight penetration would be possible in lower bound soils. In upper bound soils,161 kPa would be required to achieve the target depth underpressures of up to 161 kPa ; such underpressures would be within the operational limits, as they would not result in any risk of plug uplift (in clay) or piping (in sand).

Figure 3. Penetration plots for the penetration—Caisson A (in sand)

(left) Penetration resistance (kN) as a function of penetration depth (m). (right) Required suction underpressure (kPa) as a function of penetration depth. LB = lower bound; UB = upper bound.

Source: CATHIE



Retrieval analysis was undertaken for upper bound soils 1 day and 7 days after installation based on thixotropy, which gives a measure of how rapidly clays regain undrained shear strength after remolding. The suction caissons can be extracted from the seabed by pumping water into the suction caisson to create an "overpressure," which will push the caisson out of the soil. The required overpressures for extraction were under the maximum overpressures allowed by the caisson design.

1.4 Advance the Conceptual Design(s) for the Modular Concrete Support Structure

After Subtask 1.1, the project team concluded that enough floating stability for transportation can be provided to wet tow a fully assembled turbine if the foundation footprint is large enough or if auxiliary flotation is provided. However, auxiliary stability seems to be needed for the installation of the turbine at the site during the critical operation of support structure submersion, whether the support structure supports a fully or partially assembled turbine. The support-structure-only options did not seem to have a cost advantage significant enough to offset the cost for jack-up installation vessels and were, therefore, not further considered in Subtask 1.4. Instead, a support structure option with a telescoping concrete tower was considered to evaluate if such a system could ease the installation of the nacelle at the marshaling plant and the submersion operation of the turbine assembly at the installation site for a 50-m water depth.

In Subtask 1.4, WSP USA updated and increased the design resolution of the initial modular concrete support structure sizing performed in Subtask 1.1 using the results of Subtasks 1.2 and 1.3. Professional judgment was used to identify suitable marine-grade construction materials and configurations for modular mass production. The design update included conceptual detailing of post-tensioning layouts and tower joints. The refined conceptual structural analysis included a stress check at the service limit state and ultimate limit state.

The designs were subjected to an optimization calculation performed in Mathcad to minimize the overall support structure weight while still meeting all the defined constraints and conceptual design objectives. Ten dimensional parameters were varied, including shaft diameter at the seafloor, shaft wall thickness at seafloor and top, leg width, leg height at shaft connection and suction pile connection, and leg flange and web thickness at shaft connection and suction pile connection. Stress, buoyancy, and dynamic calculations were based on linear elastic beam theory to model the shaft and legs using Mathcad. Floating stability analysis was based on the evaluation of the metacentric height and righting moment and did not take any dynamic effects into consideration. These parameters provide a good measure for comparison of the performance of the different options and indicate stability for low-wave conditions such as those expected at the fabrication site and marshaling site and during tow in protected waters. A dynamic stability analysis was performed in Phase II of the project to evaluate the stability during tow to the installation site and the critical operation of submersion. Finite element analysis was used to complete frequency calculations for different leg and tower scenarios.

Four support structure options were produced that meet the strength and stiffness criteria for the installed and operating wind turbine as well as reasonable floating stability criteria during transport and installation. Reasonable stability criteria were defined to allow the deployment of the assembled turbine at wind gusts of up to 11 m/s (Beaufort wind force scale 5) and secure storage of such turbines to minimize weather-related interruption during installation.

The four support structure options are (1) 35-m radius tower base, (2) 40-m tower base, (3) 45-m tower base, and (4) 40-m tower base with telescoping concrete tower. Updated dimensions and characteristics for these four options were developed. Conceptual design drawings were produced for the foundation with a 40-m base with a standard tower and the foundation with a telescoping concrete tower. All support structure options were self-floating to some degree. The smallest option with a 35-m foundation radius weighs 10,300 Te but does not meet all floating stability criteria defined for the study and needs additional stabilization during installation phases once the tower is installed. The option with foundation base radius of 40 m weighs 11,000 Te and meets reasonable design criteria for floating stability for the fully assembled turbine with or without auxiliary flotation at the marshaling plant and with auxiliary flotation during deployment and installation. The support structure with a base radius of 45 m (11,900 tons) with fully assembled turbine and the 40-m radius option with telescopic concrete tower (11,700 tons, not including concrete tower) with fully assembled turbine could potentially be deployed without auxiliary flotation.

However, all options will need stabilization during submersion at the installation site. It is likely that stabilization will thus already be provided during towing to the installation site, which made the support structure with a 40-m-radius foundation appear to be the lowest-cost solution that still meets the design objectives. However, further studies were needed to determine what kind of auxiliary buoyancy is needed for the different options and how it affects the overall project cost. A support structure with a larger base radius might be preferable if it reduces some of the stability risks and installation cost at an acceptable fabrication cost increase.

The support structure with a telescoping tower is designed to fit three concrete tower segments within the shaft that can be telescoped to the full hub height once the turbine is installed. Figure 4 shows a telescoping tower for a 6-MW turbine designed, tested, and successfully built and erected by ESTEYCO as part of the ELICAN Project, a 3-year project co-financed by the European Commission. The telescoping tower allows the lifting height at the marshaling plant for tower segments, nacelle, and rotor to be limited to 65 m above the waterline rather than the 190 m for a conventional steel tower. The tower segments are installed on top of the hub from the inside out; that is, the smallest top segment is placed first, and the larger, lower segments are installed in vertical sections around the already placed segments and joined with closure pours. The shaft is installed last, possibly in the same manner. The telescopic concrete tower is lifted by means of strand jacks one segment at a time, and the segments are permanently bolted together with means of grouted post-tensioning bolts.

Figure 4. Telescoping tower for 6-MW wind turbine for the ELICAN Project

Source: Esteyco

The weight of the 40-m-radius support structure for a telescoping concrete tower is about as much as the weight of the 45-m-radius option for a conventional tower and, in its lowered position, does not seem to provide much additional stability for the deployment of the turbine to the installation site. However, at an estimated fabrication cost of $1,600,000, the 2,860-metric-ton heavy telescoping concrete tower might possibly be more cost-effective than a conventional steel tower, especially if the cost for the additional telescoping operation at the installation site can be offset by cost savings at the marshaling plant due to the reduced lifting height of the nacelle to 70 m instead of 190 m measured from the waterline. However, the telescoping tower adds complexity to the design and qualification of the tower segment joints and possibly adds inspection and maintenance work due to additional hundreds of large post-tensioning bolts at the tower segment connections. Nevertheless, the telescoping tower should remain an option in consideration, as it offers the unique feature to lower the turbine height during transportation.

In conclusion, Subtask 1.4 demonstrated that the three-legged suction pile concrete support structure is scalable and can be adjusted to specific design objectives such as turbine rating, water depth, marshaling plant constraints, installation methodology, and risk tolerance within reasonable cost variations.

1.5 Identify the Support Structure Assembly Process, and Estimate Production Rate and Costs

The primary objective of Subtask 1.5 was to develop a technically feasible conceptual assembly process for RCAM's fixed-bottom concrete support structure for a 15-MW offshore wind turbine that does not require a heavy-lift vessel. The primary manufacturing and assembly goals are:

1. Utilize the existing concrete supply chain in the eastern United States using close to 100% domestic content.
2. Develop an assembly process with flexibility that can be generalized across the eastern United States.
3. Leverage economies-of-scale manufacturing and construction methods to reduce installation costs and shorten production schedule for improved overall project LCOE.

In Subtask 1.5, University of Nebraska–Lincoln (UNL) developed conceptual assembly processes that use existing concrete casting methods and technologies including cast-in-place, precast, and post-tensioning construction, based on the preliminary design concept detailed in Subtask 1.4. The primary wind turbine foundation substructure concept analyzed in this study was the 45-m fixed-bottom concrete tripod with steel suction bucket design to be installed at an offshore site with 67 wind turbines located off the U.S. East Coast. UNL also developed a preliminary cost estimate and production analysis for the substructure design.

An existing concrete casting facility on the East Coast, Coastal Precast Systems in Cape Charles, Virginia (formerly the Bayshore Precasting Concrete Products Corporation), was used as a basis of analysis for the concrete casting production and assembly process. However, this process can be generalized to many existing concrete casting facilities at various port locations on the U.S. East Coast. The general assembly approach was to break up the activities into three major scopes of work: the fabrication or casting of the concrete foundation substructure, the marshaling and assembly of the turbine components, and the deployment and final installation of the fully assembled wind turbine with concrete fixed-bottom substructure at the final site location at sea. This study analyzed the assembly process at the fabrication site and the marshaling site.

UNL developed two assembly concepts in partnership with Structural Technologies, a heavy-lift and post-tensioning company, for casting the concrete tripod legs. One concept utilizes concrete tilt slab construction methodology with the use of tilt tables, and the other uses more traditional forming practices with match casting. Figure 5 shows the first concept, tilt wall assembly, and Figure 6 shows the second concept, traditional forming with match casting.

Figure 5. Concept Option 1: Concrete tilt slab construction methodology

Source: UNL

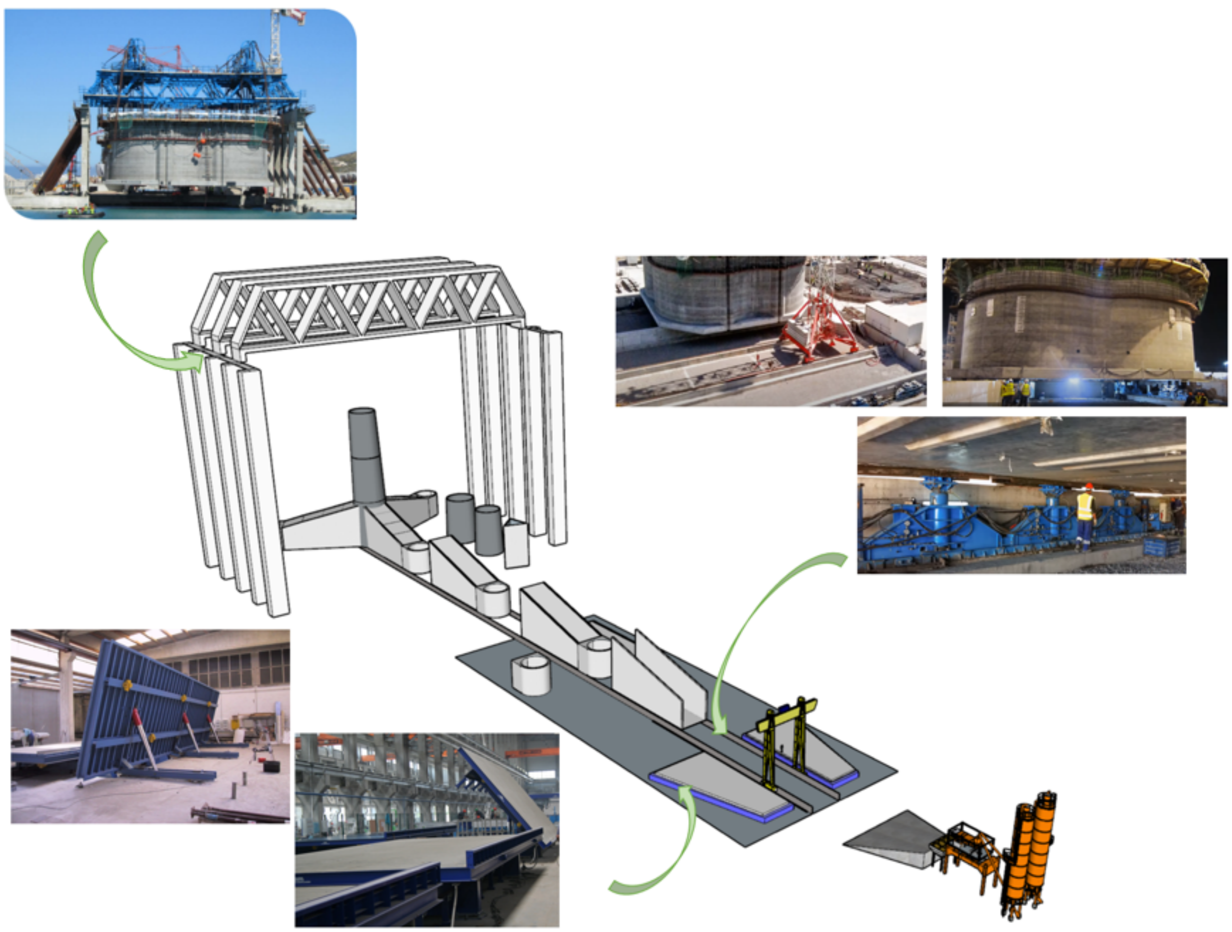
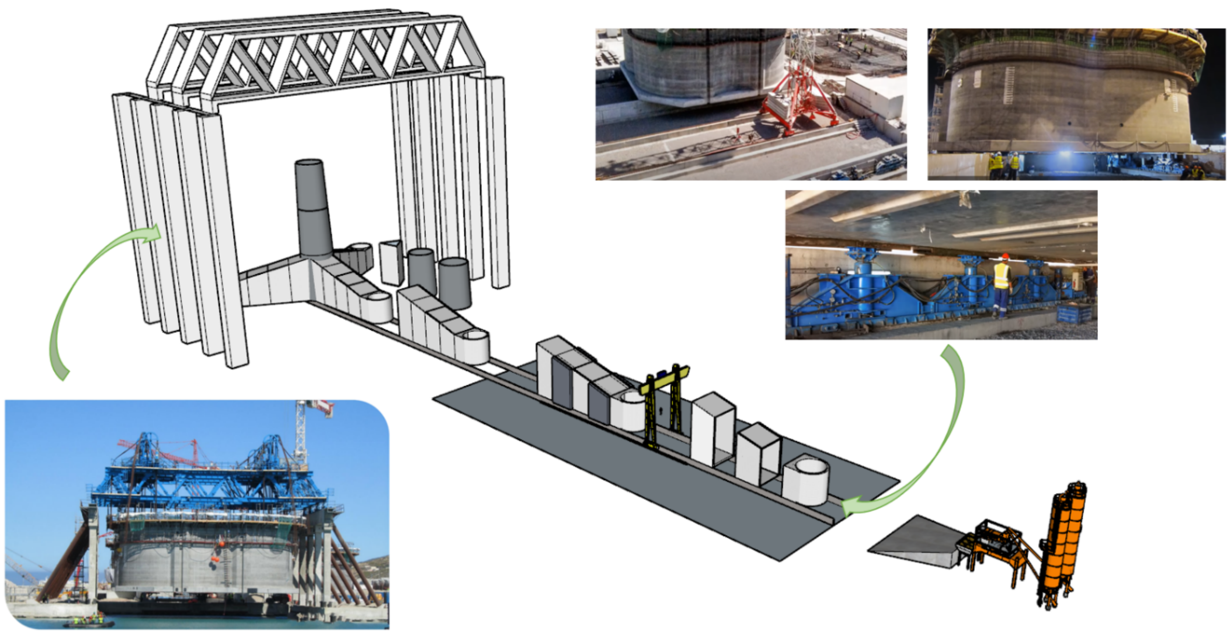


Figure 6. Concept Option 2: Traditional forming system with match casting process

Source: UNL



For both concepts, a concrete casting house will be built at the concrete facility to fabricate the components in a more temperature-controlled and weather-resistant environment. "Production lanes" will be developed for each concrete leg fabrication starting in the casting house with casting of the leg walls at various stations. Three production lanes are planned, one for each leg of the foundation; the legs will be produced simultaneously. Additional improvements to the fabrication facility will include installing a heavy-lift hydraulic jacking and rail system to move the concrete components down the production line. The hydraulic jacking system will transport each completed leg outside the casting house to a foundation assembly area where all three legs are oriented and joined to form the final tripod configuration for the foundation. A precast hub piece will be inserted with post-tension anchors between the three legs, and the tripod will be post-tensioned to required specifications. Precast shaft sections will be erected on top of the tripod and post-tensioned vertically. A closure pour will be placed around the tripod-shaft intersection to ensure a proper water seal. A launching hoisting system will be installed on the quay to launch the completed tripod foundations into the waterway. Suitable launching hoist systems have been used for the installation of concrete caissons at APM Terminals MedPort Tangier port facility in Morocco by VSL Heavy Lift International. Alternative methods of launching the foundation in the waterway are possible, such as dry docks. Once launched into the existing waterway, the concrete substructure is transported to the marshaling site, such as the New Jersey Wind Port, for full turbine assembly.

UNL prepared a preliminary cost estimate for manufacturing and assembling the foundation for the 45-m-radius tripod concrete foundation design detailed in Subtask 1.4 for a 67-wind-turbine generic site located off the U.S. East Coast at 50–60 m depth. The wind turbine tripod concrete design costs were derived from a deterministic estimate incorporating input provided by subject matter experts. Material costs used for concrete, reinforcing steel, and post-tensioning were location-adjusted to represent material costs in the state of New Jersey in 2020. The labor rate used was the current prevailing wage in New Jersey. Heavy-lift equipment rates were validated by an external heavy-lift equipment supplier to include mobilization costs to the East Coast and monthly rental rates. The RCAM concept shows increased foundation fabrication and assembly costs compared to monopiles; however, cost savings will be realized in the assembly and installation of the wind turbine at sea.

UNL updated the Phase I preliminary cost estimate in Phase II for an updated support structure design as part of subtask 6.5. Table 5 is a comparison of the 15-MW wind turbine foundation material and installation costs and the wind turbine assembly and installation costs compared to a 15-MW wind turbine monopile foundation and installation methods. The table lists the updated costs developed in Phase II because the team has higher confidence in the more developed design and cost estimating results from Phase 2. The Phase I subtotal and cost per kW are also provided in Table 5 for reference.

©

Table 5. Phase II cost summary table comparing cost per 15-MW wind turbine for the monopile foundation as compared with the fixed-bottom concrete tripod foundation concept

Foundation Capital Cost Line Item	Cost Per Wind Turbine Monopile	Cost Per Wind Turbine Tripod Concrete
Labor: Form Reinforce Pour and Post Tension Structure		$5,370,855
Material: Concrete, Reinforcement and Post Tension		$2,968,013
Equipment: Assembly Equipment and Facility Improvements	**$6,345,000** ($6,345,000)	$513,667
Supervision, Profit and Administrative		$718,266
Foundation Subtotal per wind turbine (Phase 1 preliminary results for reference)		**$9,570,801** ($7,488,984)
Cost per kW (Phase 1 preliminary results for reference)	**$423 per kW** ($423 per kW)	**$638 per KW** ($499 per kW)

Primary risks were identified during the development of the preliminary fabrication and assembly process of the new fixed-bottom concrete tripod foundation concept. Some of the identified risks include having port facilities with direct access to oceanic waterways available for upgrade or repurposing to meet the fabrication needs of the proposed concept as well as having enough production facilities and/or space to meet the production rate demands of the project.

Opportunities to improve efficiency, cost, and production of the concrete tripod foundation design concept were identified. For example, further optimization of design can allow for reduced material and assembly costs and increased production rates. In addition, reducing the cost of the hoisting and launching equipment designated for production was believed possible. Automated formwork systems and 3D concrete printing may further increase efficiency and production rates and reduce labor costs, which make up a large portion of foundation costs.

1.6 Update the Product Development Project Plan and Assess Organizational Strength

Subtask 1.6 involved updating the Phase II project plan and describing the contractor's organizational strength, hiring strategy, personnel, and resources. RCAM updated the project plan based on key findings for the conceptual design, risk analysis, and cost reduction opportunities revealed in Phase I, including:

- All modular concrete design alternatives considered were concluded to be technically feasible.

- Three transportation and installation concepts have been initially validated that would allow transportation and installation of the modular concrete support structure with the turbine fully assembled without a heavy-lift wind turbine installation vessel, reducing installation costs and installation durations from over 8 months to 4 months.
- Additional potential cost savings can be found in the concrete fabrication processes. 3DCP has the potential to cost-effectively manufacture substructure components, such as the suction buckets, legs, hub, pedestal, and tower, and the potential to increase the production rate.
- The most substantial technical risk identified for the project is the structure's stability during the submersion and installation process. The substructure's overall CapEx has been identified as the most considerable nontechnical risk, and the most important cost reduction opportunity.
- Numerous offshore wind and concrete manufacturing technology developments have occurred since RCAM's project proposal was drafted and submitted in June 2019. Awareness, acceptance, and interest in using 3DCP for wind energy structures have increased substantially, particularly in 2021.
- Numerous large-scale demonstrations have occurred for 3DCP projects, including a large-scale land-based wind turbine tower demonstration.

The approach for identifying potential work plan updates to the Phase II project was to address the primary risks, challenges, and opportunities for further cost reduction identified in Phase I by making modest changes that the teams believe are within the originally proposed scope, schedule, and budget. The revised Phase II objectives are similar to those planned initially but with three additional objectives that reflect more emphasis on performing additional conceptual design activities, but slightly fewer preliminary design activities. The three new objectives that were added to Phase II are:

- Advance the new concepts for 3DCP substructure legs and 3DCP suction buckets identified in Phase I of the project.
- Create a conceptual manufacturing and assembly process for using 3DCP during manufacturing and assembly and compare to conventional modular manufacturing.
- Simulate the new towing and installation concepts identified in Phase I.

The most significant task updates needed to achieve these new objectives in Phase II were to Task 6 (advance the design of the modular support structure and simulation of heavy-lift vessel alternative) and Task 7 (plan follow-on structural testing, field demonstration, and certification activities). However, in general, the changes required were modest with only text changes needed to some of the task numbers, subcontractor budgets, team members, milestone deliverable schedule, project duration, and Go/No-Go decision point dates. The updated project plan also included a description of RCAM's organizational strength, hiring strategy, personnel, and resource assessment needed for the modular support structure's continued development.

2 Assess Technical Feasibility of Support Structure Transportation and Installation Concepts

Task 2 focused on assessing the technical feasibility of wet towing and installing the support structure and turbine to the installation site in different levels of assembly. Subtask 2.1 considered the qualitative and quantitative assessment of risks, challenges, practicality, and benefits, of using auxiliary flotation and stability, and/or telescoping tower systems to wet tow and install RCAM’s modular concrete support structure with the turbine fully assembled, without heavy-lift wind turbine installation vessels. In addition, concept variants for the modular concrete substructure geometry are generated and qualitatively assessed. Subtask 2.2 focused on estimating the costs to transport the modular support structure to the marshaling site and the installation site for two assembly configurations.

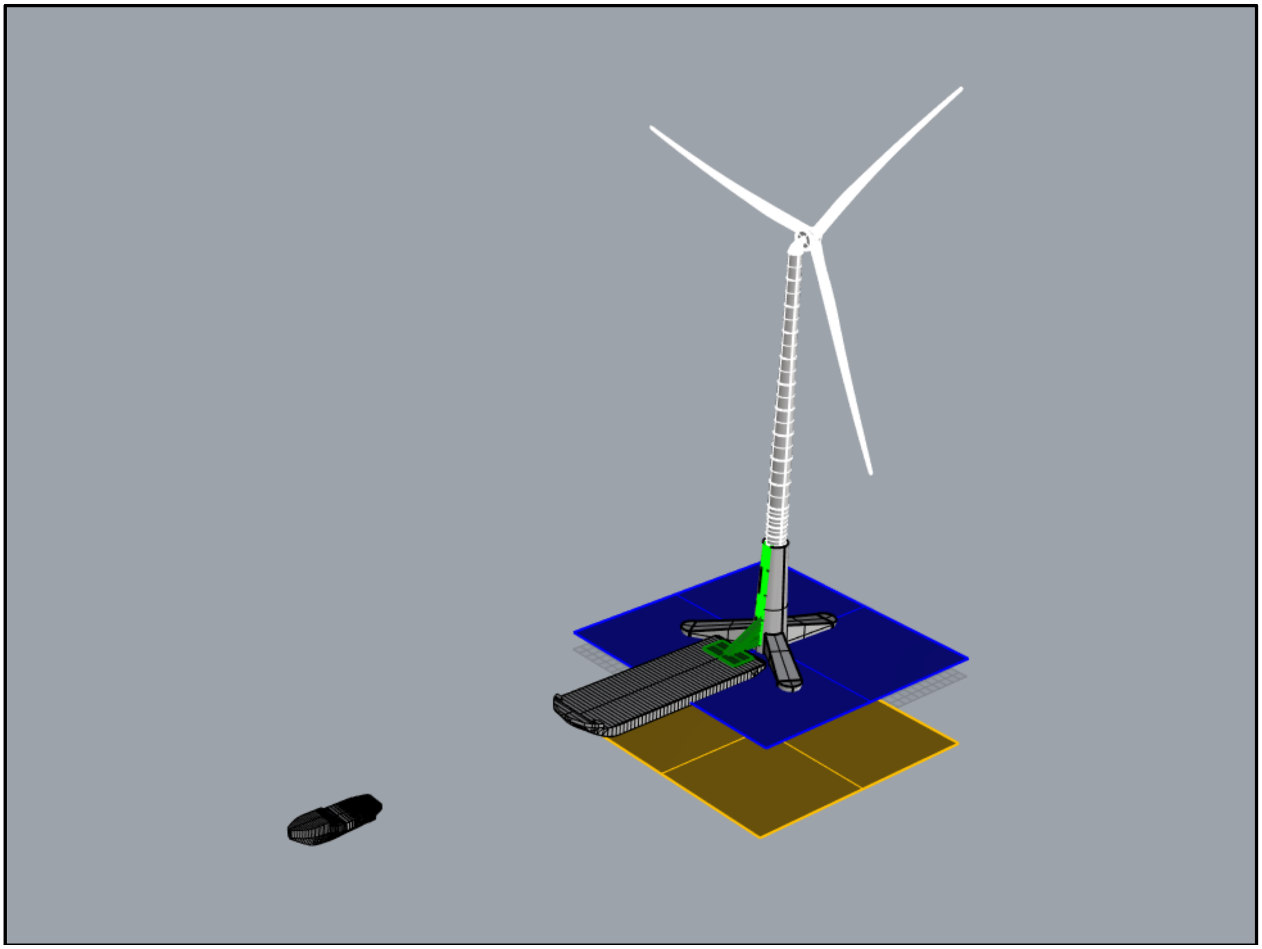
2.1 Feasibility Assessment of Transport and Installation Systems for the 15-MW Modular Suction Pile Support Structure Using Auxiliary Floatation and Telescoping Tower Systems

NETSCo led Subtask 2.1, identifying three feasible concepts that would allow for transportation and installation of the modular concrete support structure with the turbine fully assembled, without the need for a heavy-lift wind turbine installation vessel. The three concepts are (1) a deck barge with jack-up legs, (2) a deck barge with auxiliary flotation, and (3) Esteyco’s auxiliary flotation system (Esteyco n.d.).

One major, novel component of this investigation has been the conceptualization of using a low-cost deck barge as a common ocean-classed, Jones Act, auxiliary flotation device. This concept was developed as a potentially more suitable choice for the U.S. market that uses readily available U.S. equipment. The primary option investigated in the study was the use of an existing ocean-going deck barge coupled to the substructure through a pin-type connection, like those used on many articulated tug barge units. Figure 7 illustrates this concept in transport configuration. It is a flexible concept that facilitates other options as further stabilization means, such as jack-up legs. The coupling system intended to be used for the barge connection to the substructure is commercially available and proven. It would be fixed in heave, pitch, and roll during the tow, but able to be decoupled in heave during installation, allowing the support structure to be ballasted to its installation draft and firmly secured to the bottom before the connection is fully released. This would allow the barge to provide increased stability during transportation and installation.

Figure 7. Jones Act deck barge with pin connection-transport configuration overview

Source: NETSCo



Hydrostatics calculations were performed to assess support structure stability with respect to DNV-recommended criteria and environmental conditions using general hydrostatics and stability. The support structure was conceptually designed for the governing load cases and design criteria taken from the reputable available industry standards or previously defined project design limits. These criteria were built into the hydrostatic analysis program to effectively calculate results for multiple variations of the geometry. The support structure geometries and hydrostatic properties (weight and center of gravity) were obtained from Subtask 1.1. The hydrostatic analysis showed that the support structure with a 40-m leg radius and fully assembled turbine can be stable during the initial launch, marshaling, and transportation phases of deployment. During the installation and submergence of the support structure, the stability needs to be increased. NETSCo identified two feasible solutions to achieve the additional required stability including proven jack-up leg technology retrofitted to the barge, or by installation of some installation-specific means of auxiliary flotation.

Esteyco's proprietary auxiliary flotation design, "Transportation Installation and Maintenance platform", was considered as a viable alternative that would need to be scaled up for the 15-MW turbine being investigated in this project, which is understood to present a risk of high cost. Other alternatives such as a "buoyancy can" option, similar to the TetraBase, and a "tension leg platform" option drawing on experience from oil and gas technologies were conceptualized. However, the size and height of the cans for deeper installations could be cost-prohibitive and the temporary connection to the substructure challenging to make. The tension leg platform concept would allow for a lower draft of the substructure without the need for telescoping suction piles, and if a larger radius substructure were used, there is potential that this solution could remove the reliance on stabilization during transport, as it would provide all the required stabilization during installation.

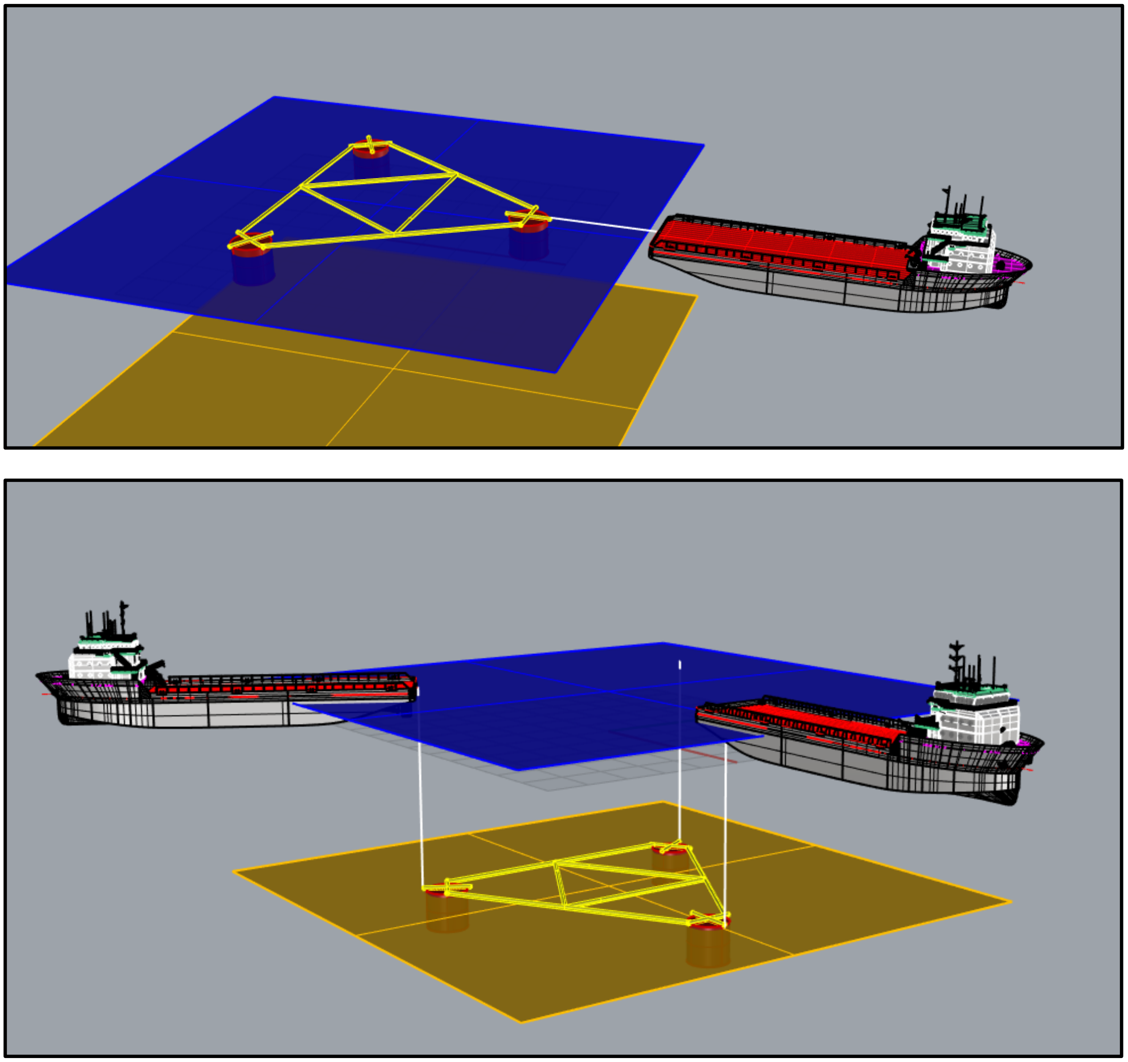
The team has identified the submersion process as the primary challenge for the overall fixed-bottom substructure. Further design optimization and analysis was performed in subsequent tasks to down-select one concept for development.

2.2 Estimate Costs for Transporting, Wet Towing, and Installing the Reference and Modular Foundations

The objective of Subtask 2.2 was to estimate the costs of two transport options for wet towing and installing the fully assembled turbine. Consistent and recent vessel costs were also provided to NREL for Subtask 3.1, which estimates the capital costs and levelized cost of energy for installing the turbine both independently and fully assembled. The two options analyzed in detail were (1) the Jones Act deck barge and pin connection, retrofitted with jack-up legs, and (2) the Jones Act deck barge and pin connection, coupled with the suction bucket assembly/tension leg platform concept for installation. Figure 8 depicts the wet tow and installation in Option 2.

Figure 8. Option 2: Suction bucket substructure wet tow and installation

Source: NETSCo



The marine equipment required for the various phases of the transportation and installation of both options was identified, market rates for vessels were obtained, and transportation and installation cycle times for each phase were estimated to inform the cost estimates. Table 6 provides a summary of the required marine equipment for the various phases of the transportation and installation cycle.

Table 6. Numbers and types of marine equipment required for the various phases of the transportation and installation processes

ID#	Marine Equipment Description	From Launch Site to Marshaling Site	From Marshaling Site to Installation Site	Installation Site		
				Fully Assembled Turbine w/ Cans	Fully Assembled Turbine w/o Cans	Assemble Offshore
1	Jones Act Deck Barge + Pin Connection		1	1	1	1[1]
2	Jones Act Deck Barge + Pin + Jack-Up Legs			1		
3	Anchor Handling Tug Vessel - DP		1	1	1	1
4	Assist Tug	2	1		2	
5	Towing Tug	1	2	2	1	3[2]
6	Deck Cargo Barge					1
7	Wind Turbine Installation Vessel					1

[1] Unassembled unit may by unstable during installation, so the X represents that it may be required.

[2] Additional Tugs required for towing of equipment and suctions cans

Upon completing the modeling of these scenarios, availability and pricing data were sourced from marine transportation and logistics companies. Hourly rates and mobilization/demobilization costs (if needed) were sourced for each vessel type. The key assumptions in the pricing model include:

1. Assembly at the marshaling site includes equipment utilized during the assembly but does not include the shore-side cost of the assembly (cranes, personnel, etc.).
2. The transportation cycle begins at the launching of the substructure and continues until the marine equipment is back at the marshaling site. From the construction site to marshaling site, it assumes separate equipment.
3. This cost model assumes that there will be a continuous installation cycle with equipment fully utilized, and no standby time.
4. Cable-laying cost is not included in the analysis.

The cost of transportation and installation was estimated to be $494,306 per turbine for Option 1 (jack-up barge), and $403,602 for Option 2 (tension leg platform concept). The main cost driver for Option 1 is the requirement for additional stabilization for the installation of the substructure provided via the addition of jack-up legs to the flotation aid. The cost-benefit in transportation and installation for the fully assembled turbine compared to using a wind turbine installation vessel for the monopile reference configuration is further described in Subtask 3.1

3 Develop Reference Model and Perform Levelized Cost of Energy Analyses

3.1 Perform Levelized Cost of Energy Analysis

The objective of Subtask 3 was to perform a preliminary comparative assessment of three LCOE scenarios for a 1,005-MW wind plant comprising sixty-seven 15-MW wind turbines using different foundations. NREL evaluated LCOE using the Offshore Renewables Balance-of-system Installation Tool (ORBIT), a process-based cost model developed by NREL. Three scenarios were compared: (1) a conventional monopile installed using a WTIV with a feeder barge, (2) a concrete tripod that is installed using tugboats and other low-cost vessels followed by a WTIV that assembles the turbines on top of the installed tripod, and (3) a concrete tripod and turbine that are assembled at quayside, then wet towed and installed at the offshore wind plant using tugboats, thus circumventing the need for a WTIV, similar to the scenario for a deck barge with auxiliary flotation described in Subtask 2.1.

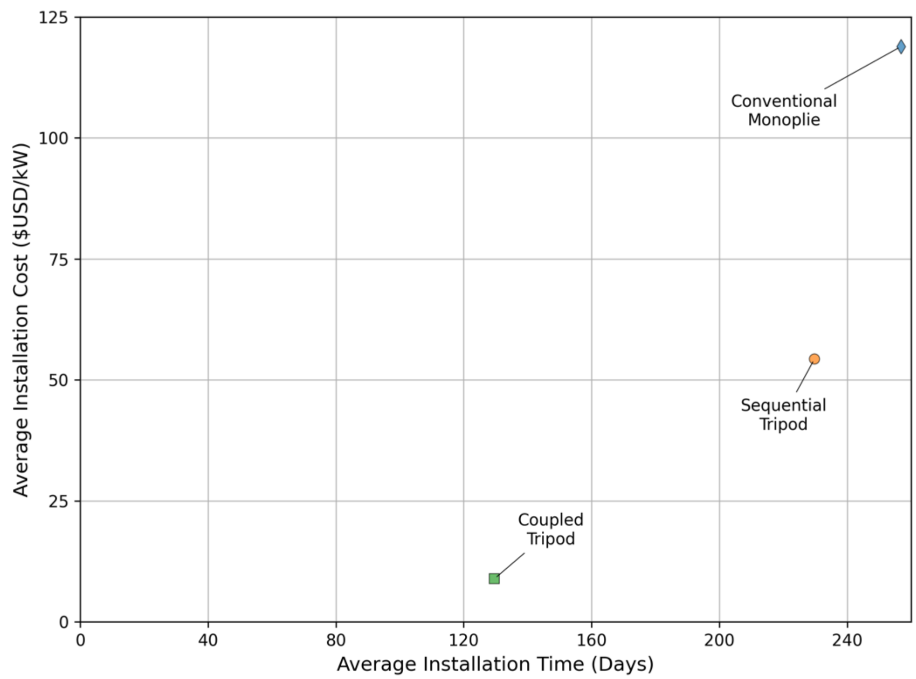
NREL outlined the three scenarios in sufficient detail to be modeled in ORBIT. NREL used an hourly wind and wave weather profile from the Atlantic Coast to evaluate weather delays during the installation simulation. Vessel characteristics were developed by the project team with specifications from vessel operators obtained by NETSCo. The ORBIT simulations were conducted over multiple calendar years and reported average costs, times, and delays, which vary with the weather time series from the individual years. While ORBIT features a set of baseline generic designs and installation processes, it is also designed to be flexible and modular so that novel technology or process innovations can be easily introduced into the model. The costs, installation durations, and weather delays computed by ORBIT have been reviewed by industry practitioners, compared with publicly available data, and benchmarked against similar models. Turbine CapEx, scour protection CapEx, operational expenditures, fixed charge rate, net capacity factor, and soft costs were assumed to be constant across all scenarios. Appropriate assumptions were compiled for each scenario based on the project outcomes and industry and literature data.

Figure 9 shows the average installation cost and average installation time for each scenario, where each data point is the average of data from the 33 simulation runs with different starting years. Clearly, the coupled tripod scenario achieves the lowest average cost and lowest average installation time, whereas the conventional monopile solution is the most expensive and requires the longest duration. Both the sequential and coupled scenarios realized significant cost reductions for the foundation and turbine installation phases, with the installation costs of the sequential and coupled scenarios reduced by 54.3%

and 92.5% relative to the monopile scenario, respectively. Shifting from a conventional monopile strategy to the concrete tripod with coupled turbine installation reduces the installation costs substantially, from $118.90/kW to $8.90/kW. In absolute terms, this is equivalent to a reduction from $119 million to $9 million for a 1,005-MW plant. This is achieved not only by eliminating the expensive WTIV from the installation vessel spread, but also by decreasing the installation time from 257 days to 130 days. The conventional monopile scenario uses only one WTIV due to cost and scheduling constraints for WTIVs, which results in only being able to install one foundation at a time; conversely, the concrete tripod scenario allows the more readily available tugboat and anchor handling tug supply vessels to install foundations in parallel.

Figure 9. Average installation costs compared to the average installation time for the foundation and turbine installation phases in each of the scenarios

Source: NREL



Despite these significant reductions in installation cost, the overall CapEx and LCOE numbers did not decrease significantly. The overall CapEx for the monopile was $3,380/kW compared to $3,392/kW for the sequential tripod and $3,357/kW for the coupled tripod. The LCOE results were $74.80/MWh for the monopile compared to $74.90/MWh for the sequential tripod and $74.50/MWh for the coupled tripod. This minor effect on overall CapEx and LCOE was due to the fact that installation costs comprise a minor fraction of the overall costs compared to turbine and foundation CapEx, and that the installation cost reductions were somewhat offset by increases in substructure CapEx. The total project CapEx value derived from the ORBIT runs is around $3,400/kW, which is slightly lower than reported global average values (Beiter et al. 2020), which can potentially be attributed to the economies of size associated with the higher turbine ratings of the modeled projects. In these same model runs, the foundation and turbine installation costs are 3.5% of the overall CapEx costs—again, this result is in line with published CapEx breakdowns (Beiter et al. 2020). Therefore, the contribution of decreasing the costs of the foundation and turbine installation phases will have a restricted marginal value relative to the project CapEx and, further, the LCOE. Finding opportunities to reduce the capital cost of the foundation represents a more significant cost reduction opportunity than reducing the installation costs.

However, the true value of the concrete foundation is likely not fully captured by LCOE. Several key benefits such as reduced contractual, weather, supply chain, and environmental risks, were identified for the concrete tripod relative to the monopile. The concrete tripod reduces risks and challenges associated with the scarcity of WTIVs in the global market, long monopile installation timelines, dependency on European supply chain, and environmental impacts of monopile installation. The quantitative significance of these parameters was not yet clear relative to LCOE; however, their impact on project viability is potentially paramount and was identified for further investigation in Task 6. The results of this preliminary analysis were used to inform the down-selection of concrete foundation designs and installation methods developed by the project team, and laid the groundwork for Subtask 6.6, which refined and updated the calculations with the finalized design parameters and further investigated non-LCOE benefits.

4 Stakeholder/Advisory Panel Down-Selection Workshop

The project team held a stakeholder/advisory group workshop on October 29, 2020. The primary objectives of the stakeholder workshop were to review and obtain stakeholder feedback on the results of recently completed Phase I tasks and the revised Phase II workplan. Specifically, the project team sought to inform the down-selection of support structure and transportation and installation configurations to advance in a subsequent task, and to discuss the selection criteria and candidate sites for the northeastern manufacturing, assembly, and installation sites.

The workshop was originally planned to be a one-day, in-person workshop. However, the resurgence of the COVID-19 pandemic necessitated that the workshop be held virtually to minimize risks. The virtual meeting venue provided the team with the opportunity to invite a much wider and larger audience than originally anticipated. Key stakeholders invited included offshore wind developers, potential supply chain partners, project partners, state and federal funding agencies, the advisory panel, subject matter experts, and consortium members. Out of 54 invited attendees, 42 attended. However, the workshop length was reduced from a full day to one-third day due to the challenge of attracting a large diverse stakeholder audience to the less effective virtual communication medium compared to an in-person meeting. Additional private discussions were held with the advisory panel members from Equinor, Shell, and Kiewit to obtain more detail and depth for down-selecting design and site selection decisions in Phase II.

The key outcomes of the workshop and advisory panel discussions are summarized below. General feedback was provided that the idea seems novel and that the team is headed in the right direction. Stakeholder feedback indicated that low-cost options continue to be the key decision criteria; however, the project team was encouraged to keep an open mind toward alternative concepts and features within the available scope and budget that could potentially provide value proposition, such as low CO_2 concrete and ecofriendly features. There appeared to be more interest in the deployment of fully assembled turbines and heavy-lift vessel alternatives than originally thought at the start of the project. It was noted that installation solutions that are relatively simple, quick, and low risk appeared to be the most attractive options to stakeholders. Alternative anchor solutions to suction buckets, such as traditional piles, also appeared to be of interest to stakeholders and could address a primary and common stakeholder concern that suction buckets do not work everywhere.

Based on the workshop outcomes, the project team decided to also consider concepts that potentially allow for the use of driven piles and even gravity bases as "preinstalled" foundations that can be used as the foundation for the tripod. For example, the preinstalled suction bucket can also be used with hammered piles. For this reason, the project team changed the name of the concept to *preinstalled foundation*. Other variants on the preinstalled foundation could be promising, such as increasing the height of the preinstalled foundation section, and should be explored for the following potential benefits:

- Reducing the stem height during wet towing for increased stability and making the design more suitable to regions with bridges; thereby reducing the need for telescoping towers.
- Potentially simplifying the installation process and reducing installation time.
- Providing ultra-long-life preinstalled foundations that act as infrastructure and can be used for more than one substructure and/or turbine.

Regarding reference port sites, the project team was encouraged to consider ports in various states including New Jersey, New York, Texas, California, and Maine, and consider the Port of Coeymans as a reference point.

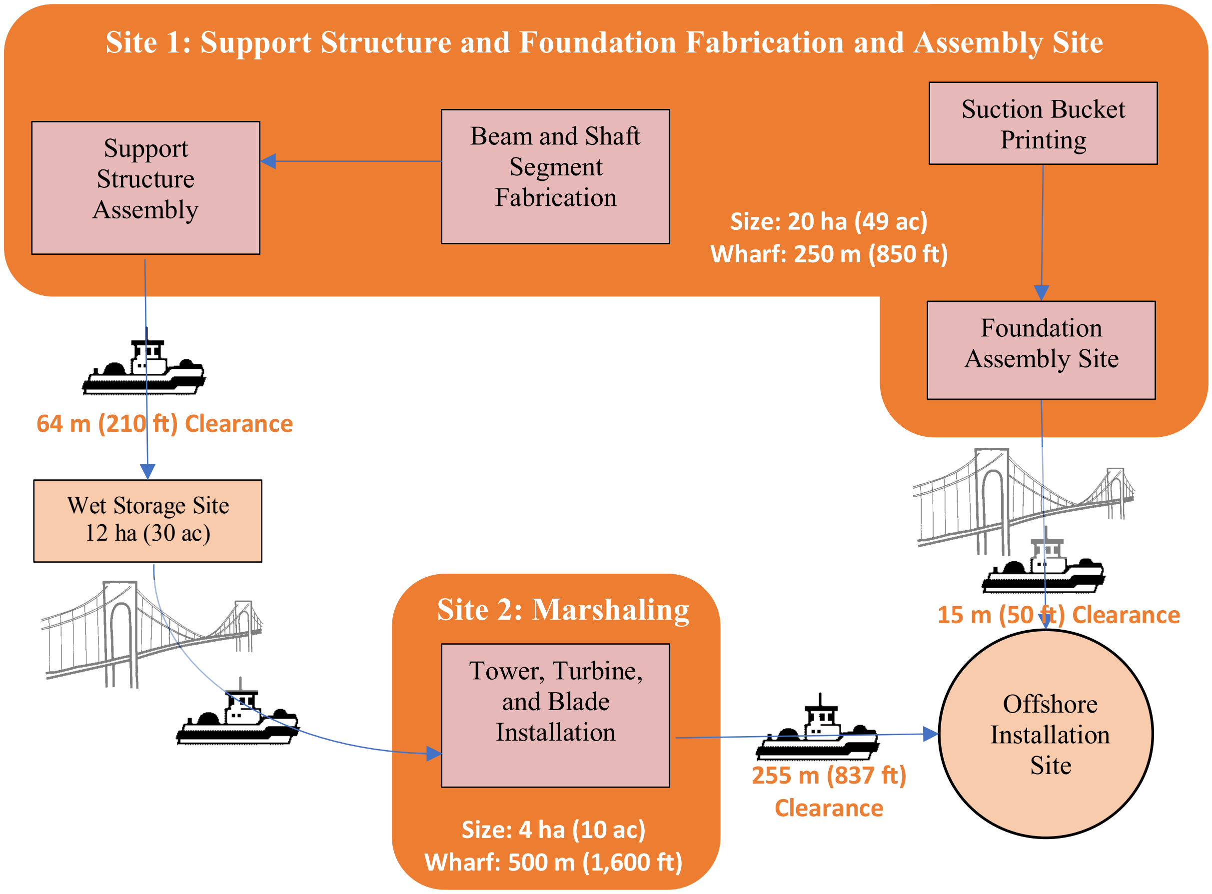
5 Identify Northeastern Reference Sites for Manufacturing, Assembly, and Installation

Task 5 focused on assessing sites in the northeastern United States for their potential to serve as references sites for analyses of manufacturing, assembly, and launching the modular concrete support structure. In Task 5, WSP identified the general wind farm locations suitable for the deployment of the novel modular concrete suction bucket support structure on the U.S. East Coast and identified eight possible site scenarios for the manufacturing and marshaling of turbines for these locations. This desktop study was performed by collecting publicly available information from the internet, including publicly funded study reports on ports and manufacturing facilities on the U.S. East Coast. WSP first developed a set of search criteria for fabrication, assembly, and marshaling sites (or combinations thereof), including site bearing capacity, minimum channel widths, allowable construction area, availability of barge slips or wharfs with sufficient water depth, and vertical clearance of channels. WSP considered several scenarios based on different combinations of sites. These scenarios included a one-site scenario where all components are fabricated, launched, and assembled at a single location, a five-site scenario where each construction operation is performed at a separate location, and variations thereof.

Figure 10 shows a schematic of the two-site scenario, which comprises a support structure and foundation fabrication and assembly site and a marshaling site. In the two-site scenario, it is assumed that all fabrication and assembly is performed at one site, where the support structure is launched and wet towed to a second site, the marshaling site. The Virginia Coastal Precast Systems site and Delaware marshaling site analyzed in Phase I of the project are examples of the two-site scenario. The fabrication and assembly site need to be large but can possibly be at a port farther inland, as an air draft of 64 m (210 ft) is sufficient to tow the concrete structure. The marshaling site still requires unlimited air draft ocean access, but the space needed at the marshaling site is much smaller.

Similar to the one-site scenario, the 3D printing, assembly, and launch of the concrete suction buckets and foundation frames is assumed to be an independent deployment cycle performed at the larger fabrication and assembly site. Note that the assembled concrete support structure height is still considerable (64 m), and there are only a few bridges in the Northeast that provide enough clearance to allow wet towing.

Figure 10. Two-site scenario: Separate marshaling site



The deployment costs were considered in the analysis of marshaling sites based on prior project tasks that identified required vessels and estimated their cost. Four sites along the northeast coast of the United States were noted as feasible marshaling sites for this project with unrestricted air draft and sufficient channel width to tow the concrete support structure with mounted turbine: (1) the State Pier in New London, Connecticut; (2) the Arthur Kill Terminal on Staten Island, New York; (3) the New Jersey Wind Port at the Delaware Bay in Salem County, New Jersey; and (4) the Portsmouth Marine Terminal in Portsmouth, Virginia. All these sites are in waterways that provide ample marine construction capabilities. However, from these sites, only the State Pier in New London and the Arthur Kill Terminal in New York are within 150 nautical miles of deepwater installation regions of current BOEM call areas. Accordingly, the study focused on fabrication and assembly sites that could cater to these two potential marshaling sites. Nevertheless, all components or even the entire substructure could be manufactured at more remote sites and barged or towed as needed. This finding supported the project team's hypothesis that a variety of suitable facilities and associated supply chain facilities exist or are in development near expected future offshore wind plants. Although outside the scope of the study, the team expects the facilities identified are also well suited to manufacturing and assembling floating foundations and mooring components for the East Coast.

The team concludes that the manufacturing, assembly, and deployment of the modular support structure technology is feasible in the BOEM call areas of the East Coast. The report identified eight scenarios with sites that could host major fabrication and assembly of the concrete modular foundation. The sites are in states that could potentially be an offtaker to expected wind developments in water depths of 50 m (164 ft) or greater, including Massachusetts, Connecticut, Rhode Island, and New York. The selected facilities at these sites either already exist or are in planning stages. Once fully developed, all are expected to meet the search criteria with only modest project-specific improvement needs.

In addition to the facility features, capacity, and location parameters considered in this study, there are a multitude of other factors that affect the decision of which facility to use for fabrication and assembly, including the availability of the facility, local content requirements, environmental and stakeholder impact, financial incentives, and, ultimately, the final bid price. The variety of numerous suitable facilities and associated supply chain scenarios identified in this study is an important benefit to production of the modular concrete foundation because any of the previously mentioned decision factors can be critical decision drivers, and often the final facility decision is made late in the planning phase.

6 Preliminary Design of Modular Support Structure and Transportation and Installation Systems

Task 6 aimed to increase the fidelity of the support structure design and transportation and installation systems based on learnings from Phase I. Task 6 also included conceptual design and analysis of 3D concrete printing manufacturing for the support structure concept.

6.1 Update Metocean Loads Based On Down-Selected Support Structure Design and Northeastern Reference Site

In Subtask 6.1, WSP updated the calculated loads on the substructure from hydrodynamic and aerodynamic effects, based on the 35-m foundation base described in Subtask 1.4. Four design load cases according to DNV and IEC were investigated: DLCs 1.1, 1.6, 6.1, and 6.4. The wave loads were calculated considering the complete substructure with shaft and legs using the 3D diffraction/radiation software WAMIT. A coupled analysis was performed using the time domain program OrcaFlex. OrcaFlex uses hydrodynamic input from WAMIT and wind series generated from TurbSim. Twelve different sections of the substructure were studied, six on the shaft and six on the legs. The maximum and minimum sectional force and moment for all design load cases were calculated for the shaft and leg sections, base, and suction piles.

Table 7 compares the sectional loads from the OrcaFlex analysis in Subtask 6.1 to the loads calculated in Subtask 1.4 based on the monopile assumption. The shaded cells are the maximum and minimum extreme sectional loads and associated components for the shaft bottom section above the leg connection (S1S2). The loads seem comparable, except that:

- The base shear from the OrcaFlex analysis is about 50% higher than before, probably because the legs are subjected to additional pressure from waves and current that has been neglected in the monopile analysis. This additional shear will probably be less of a concern for the structure but will require an increase in the size of the suction buckets.
- The maximum moment at the tower connection is higher. The OrcaFlex analysis considered a ±8° yaw misalignment of the parked turbine during extreme wind condition per DLC 6.1, which probably has been neglected in the monopile analysis. This will require thickening the walls at the top of the shaft.
- In the OrcaFlex analysis, the suction buckets experience a significant moment because they are stiffly connected to the structure and the soil is assumed to be stiff sand. In the Task 1.4 analysis, it was assumed that the suction buckets are pin-connected to the support structure, which is conservative. The stiff connection leads to a reduction of the vertical loads on the suction buckets by about 11 MN and also reduces the shear and moment demand on the legs of

the support structure. In further design phases, the structure will need to be designed for a maximum and minimum soil stiffness assumption dependent on project location to optimize the legs and suction buckets.

Table 7. Sectional loads for Task 1.4 and Task 6.1

Task	Section	Component	Loadcase	Fx [kN]	Fy [kN]	Fz [kN]	Mx [kNm]	My [kNm]	Mz [kNm]
1.4	Monopile at Seabed	Min Fx	DLC6.1	-40000	-1769	50527	4.620E+04	-1.267E+06	1.438E+03
		Max Fx	DLC6.1	36707	4393	47039	-1.324E+05	1.148E+06	2.571E+03
		Min My	DLC1.6a	-32930	647	48190	-4.748E+04	-1.361E+06	1.281E+03
		Max My	DLC6.1	36643	4369	46221	-1.367E+05	1.152E+06	2.580E+03
6.1	S1S2	Min Fx	DLC6.1	-35266	0	-26280	1.576E+00	-1.147E+06	-5.418E-01
		Max Fx	DLC6.1	35112	0	-26260	4.105E+00	1.148E+06	-5.455E-01
		Min My	DLC6.4	-16732	0	-30349	-3.646E+00	-1.429E+06	-2.350E-01
		Max My	DLC6.4	16726	0	-29906	4.588E-01	1.430E+06	-1.584E-01

6.2 Analyze Seakeeping During Transport and Assembly

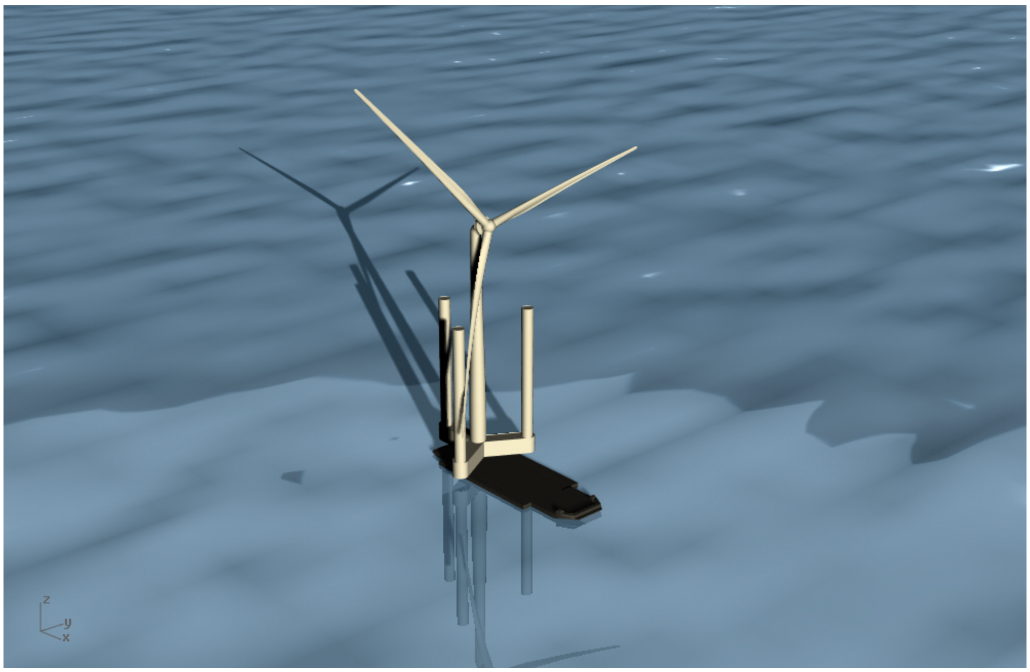
In Subtask 6.2, NETSCo advanced the seakeeping analysis of RCAM's fully assembled turbine and fixed-bottom tripod substructure and down-selected an auxiliary stability system with support from the project team. The down-selection process used three tiers of decisions to select the substructure and flotation aid configuration: Tier I. Final installed position of the substructure (above the water vs. below); Tier II. Auxiliary stability system for transportation and installation; and Tier III. Suction bucket attachment/installation method. In Tier I, it was decided to continue moving forward with a submerged foundation rather than alternative solutions in which the substructure is installed on piles above the water surface. Although the submerged foundation entails risk and costs associated with submersion, the above-water solutions would require expensive and complex operations and/or more cost-prohibitive structures.

In Tier II, the team considered several systems for transporting and installing RCAM's fixed-bottom tripod substructure: (1) barge + jack-up legs (Figure 11), (2) barge + preinstalled foundation, and (3) flotation aid. The project team elected to end the evaluation of barge-based solutions and focus on an alternative flotation aid system. The two barge solutions, while having the benefit of being based on an existing and available Jones Act vessel, ultimately had too many risks and unknowns associated with the installation component of the solutions. The team invented and down-selected a proprietary flotation aid called the Independent Pontoon System (IPS) as the best option. Specific details about the IPS concept have been omitted from this report due to business-sensitive intellectual property considerations.

The IPS solution presented a single solution to handle both installation and transportation using less complex marine operations. The IPS concept reduces a number of the inherent risks that other potential solutions pose and could be used with other fixed and floating platform technologies, such as gravity base solutions and tension leg platform floaters. The IPS is a relatively simple solution based on proven marine engineering technology. Compared to the other solutions evaluated by the team, this concept will potentially offer the lowest installation time. The IPS details and cost estimates are described in Subtask 6.3.

Figure 11. Barge plus jack-up legs solution

Source: NETSCo



The team also concluded that the two suction bucket attachment methods considered (telescoping and preinstalled) are both compatible with the IPS and decided to carry both forward as viable solutions. Carrying both options forward in the project increased the applicability of the tripod foundation solution to different installation sites and provided an alternative in the event that one option proved infeasible or less attractive to a developer.

After down-selecting the type of auxiliary stability system and specific transportation and installation system, the team carried out a targeted stability analysis, comparing the simulation results to accepted criteria and weather limits on vessel seakeeping ability. The four configurations analyzed were: (1) the substructure only in its in-port configuration, (2) the fully assembled turbine and substructure with auxiliary flotation aid connected in the in-port configuration, (3) the fully assembled turbine and auxiliary flotation aid in the transportation configuration for all installation steps, and (4) a disconnected flotation aid pontoon. The fully assembled turbine on the foundation and the IPS geometries passed all seakeeping criteria in all conditions.

The initial seakeeping analysis of the IPS completed here allowed the team to advance the design and analysis of this system. This type of flotation aid furthers the project goals of developing a heavy-lift vessel alternative that is fully scalable to future larger turbines and substructures.

6.3 Update the Transportation and Installation System Conceptual Design and Cost Estimates

In Subtask 6.3, NETSCo further described the project team's independent pontoon system and developed capital cost and operational cost estimates for the system, building upon Subtask 2.2. The objective of Subtask 6.3 was to update the conceptual design and cost estimates of the down-selected transportation and installation configuration (the heavy-lift vessel alterative) selected in Task 4 and Subtask 6.2.

NETSCo estimated the capital costs for the engineering, fabrication, and procurement of all equipment required for the development of an IPS. The cost estimates considered pricing data from U.S. Gulf of Mexico fabrication suppliers based on the current conceptual configuration. It was assumed that only one set of IPS units is used during the installation cycle. The cost model assumed that there will be a continuous installation cycle with equipment fully utilized and no standby time. Cable-laying costs were not included in the analysis. The estimated capital cost of an IPS set (a three-pontoon system) without dynamic positioning (DP) capability is $20 million and a DP-equipped alternative is $24 million.

This capital cost was then converted to installation cost per installed turbine assuming that the total cost of the IPS will be borne by one 50-turbine project. The team views this assumption as very conservative because it expects the IPS will have a 20- to 30-year life with the potential to be used to install other fixed and floating platform technologies such as gravity bases and tension leg platform floating turbines. When converted to installation cost per installed turbine and assuming capital recovery over only one wind plant, the cost is $525,000 per turbine for the non-DP option and $550,000 per turbine for the DP option. This cost includes all marine equipment, which will also be needed for a conventional WTIV-type installation. As a direct comparison on an hourly basis, current WTIV rates are $9,375/hour and the hourly rate for the IPS is $3,125 for the non-DP option and $3,742 for the DP option. There will be a further direct cost reduction per turbine if the IPS cost is distributed across multiple fixed or floating wind turbine projects. In addition to this cost advantage, the IPS can be built in several different U.S. shipyards for easy deployment to any of the planned fabrication sites, creating high-paying domestic jobs and localized economic benefits.

6.4 Conceptual Design Alternative of 3DCP Legs and Suction Buckets

In Subtask 6.4, WSP performed the conceptual design of the support structure and identified concepts for 3D printing leg sections and suction buckets. The design was updated to conceptually meet the revised load demands derived during Subtask 6.1. The base design is laid out for typical segmental precast construction. An alternative leg cross section and a bucket design have been developed that are more suitable for 3DCP. Design drawings were developed for concrete sections, post-tensioning, and reinforcement levels of the alternative leg and suction bucket that are believed to optimize toward 3DCP as a first step of optimizing section shape, minimizing mild reinforcement ratios, and maximizing the use of post-tensioning. This design can act as a basis for discussion with printer suppliers on the structural features, such as concrete properties, wall thicknesses and shapes, minimum reinforcement, and post-tensioning hardware, that a printing process has to accommodate in order to print substantial concrete components for such structures. Furthermore, the design goes into a level of detail that allows the project team to conceptually develop construction plans, fabrication layouts, and cost estimates.

The conceptual design was limited to generally meet service and ultimate state limits per DNV standard DNV-ST-0126 “Support Structures for Wind Turbines” and American Concrete Institute (ACI) standard ACI 314-16 “Building Code Requirements for Structural Concrete.” Fatigue design was not considered. The general overall dimensions of the support structure were derived by updating prior calculations using the updated loads in Subtask 6.1. The legs were designed using 3D finite-element analysis with shell elements considering hydrostatic and still-water loads during tow-out and submersion and of maximum operational loads of the installed turbine. Concrete sections and reinforcement amounts were then determined using hand calculations. The concrete suction bucket was designed using hand calculations considering maximum loads during bucket installation (seabed penetration), turbine operation, and bucket extraction at the end of service. Assumptions for loads and installation methods were taken from previous subtasks. The concept design of the support structure has been further evaluated under revised hydro/aerodynamic operational loads and hydrostatic loads during installation. The structure needed some minor upgrades such as strengthening the top of the shaft, larger haunches in the beam plating, a transverse bulkhead at mid-beam length, and post-tensioning in the beam plating in vertical and transverse direction. This updated design represents the base design.

The base design of the leg is a box cross section with longitudinal, vertical, and transversal post-tensioning. The base design provides a strong, watertight transverse bulkhead at mid-beam that allows flooding the beam half closest to the shaft before starting to flood the outer half. This reduces the differential hydrostatic pressure on the plating of the inner, taller compartment and, as a result, allows optimization of the wall thickness.

An alternative leg design with an arched top was developed as a first optimization toward 3DCP. This design sought to optimize the cross-section shape for hydrostatic pressure by taking advantage of 3D printing. Using more complex shapes enabled by 3DCP allowed the team to reduce reinforcement content, optimize the wall plating, and reconfigure the leg sections to avoid tensile stresses in the longitudinal beam direction. The printing direction can be chosen to align with the direction of higher stresses and the weaker interfaces between beads can remain under compression. Furthermore, the optimized cross section is now strong enough to carry the full differential hydrostatic pressure without dividing the beam into two buoyancy compartments.

The suction bucket is made of a concrete cylinder with helical post-tensioning and a concrete dome with steel liner. The cylinder can be built either by slip or jump forming cast-in-place concrete or it can be 3D printed. The concrete dome with the ring beam that connects dome and cylinder is envisioned to be cast in place, as all post-tensioning anchors are within the ring beam and the steel liner of the dome serves as a stay-in-place formwork. There are no post-tensioning anchors within the concrete cylinder—all tendons loop around at the cylinder bottom—allowing 3D printing of the entire cylinder without heavy post-tensioning hardware. Minimum cracking reinforcement is needed at both surfaces of the cylinder in order to meet code requirements, and it should be discussed with the 3D printing industry how to include reinforcement in the printing process or if it can be demonstrated that such reinforcement is not needed if post-tensioning tendons are sufficient to control cracks. Likewise, it is envisioned that 3D printing also provides the voids for the post-tensioning tendons. Ideally, the printer would print polymer ducts simultaneously as it builds up the cylinder. Alternative methods to install ducts after printing should be considered, such as grouting ducts into voids or installing blow-in pipe liners. The industry should also explore whether ducts can be omitted altogether if the printer can achieve a sufficiently dense concrete that protects post-tensioning strands in a marine environment without the use of ducts.

This design study identified several needs for further research and development in 3DCP technologies. The main challenges noted were methods for the installation of reinforcement and post-tensioning ducts and hardware, uncertainty regarding printing production rates for these large components, lack of available information on 3DCP material properties such as cracking behavior, the effect of the weaker interfaces between beads, and durability in a marine environment. As a next step, it was recommended to review this design with 3D printing industry stakeholders to discuss printing methods, make design optimizations, and identify 3D printing innovations needed to successfully fabricate large structural components for the marine environment.

6.5 Concrete Support Structure Assembly Process and Estimates of Production Rate and Costs

In Subtask 6.5, UNL developed and analyzed a feasible conceptual assembly process for a generic wind turbine site consisting of sixty-seven 15-MW turbines and a fixed-bottom concrete tripod foundation with steel suction buckets based on the preliminary design detailed in Subtask 6.4. The assembly process analyzed traditional concrete casting methods at the fabrication site using a supply chain with 100% U.S. East Coast domestic content, and a preliminary cost estimate was developed for a 3DCP method.

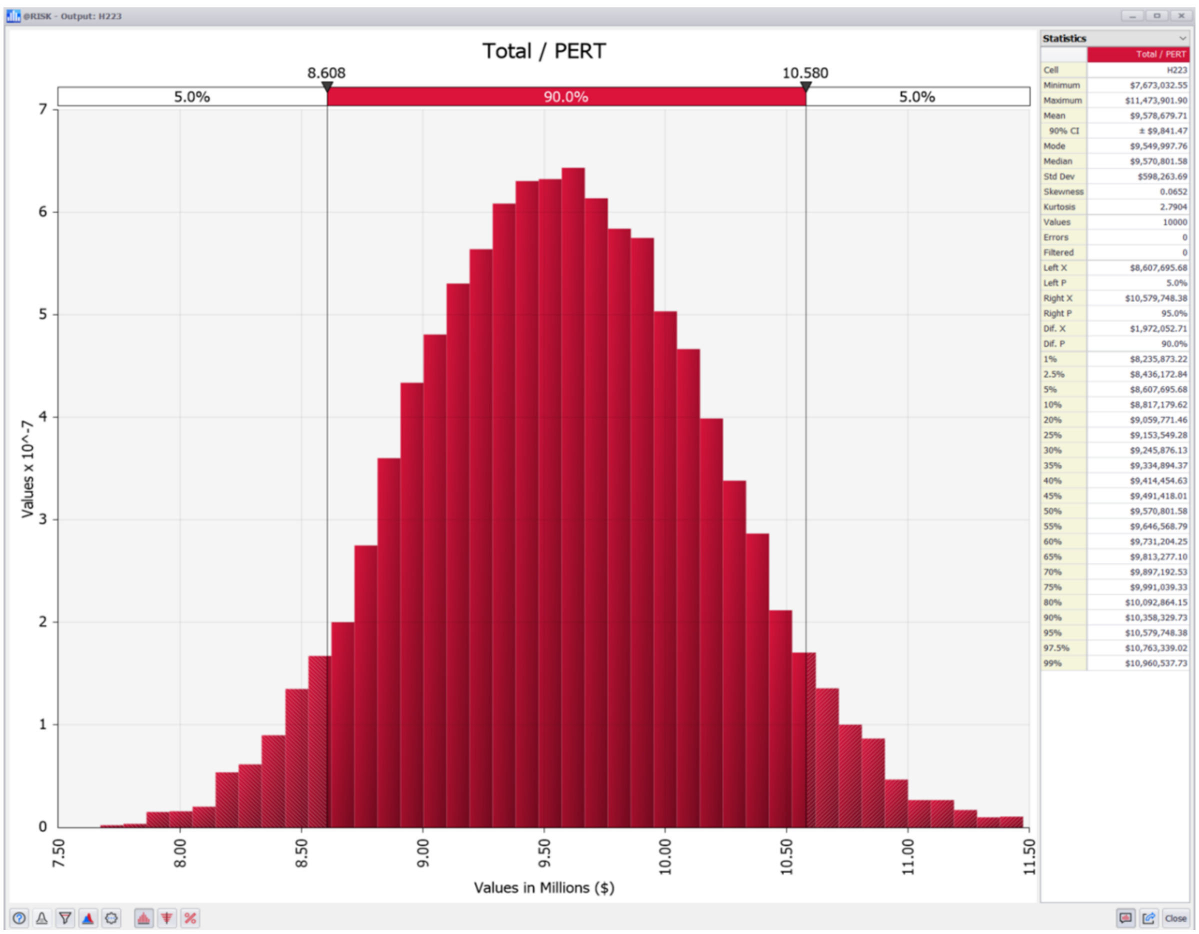
The primary objective of Subtask 6.5 was to develop a technically feasible conceptual assembly process that meets the following primary manufacturing and assembly goals:

- Utilize the existing concrete supply chain in the eastern United States using close to 100% domestic content.
- Develop an assembly process with flexibility that can be generalized across the eastern United States.
- Leverage economies-of-scale manufacturing and construction methods to reduce installation costs and shorten then production schedule for improved overall project LCOE.

A constructability review was conducted during this subtask with subject matter experts experienced in the construction of large marine concrete structures. The validated and updated assembly process is the basis of the cost and production rate analysis. A production rate of 1–2 weeks per turbine foundation was estimated as the cycle time duration of each foundation once the initial ramp-up phase is completed. South Brooklyn Marine Terminal casting yard was used as an example reference site to lay out the concrete assembly process and track system for moving and lowering the foundation into the waterway. This facility is representative of many other port facilities capable of being repurposed to become concrete casting yards at locations along the U.S. East Coast or potentially the Gulf Coast.

A probabilistic cost estimate incorporating historical data provided by subject matter experts was developed by UNL. The estimates were informed by a range of production rates from project data from previous projects in marine and bridge concrete construction performed by the subject matter experts’ organizations. Material costs used for concrete, reinforcing steel, and post-tensioning were location-adjusted to represent material costs in the state of New York in 2021. The labor rates used were the current prevailing wage in New York. Heavy-lift equipment rates were validated by an external heavy-lift equipment supplier to include mobilization costs to the East Coast and monthly rental rates. Figure 12 is the result of the Monte Carlo simulation providing a range of probable outcomes for the total cost of the concrete tripod foundation concept. The range of probable cost outcomes varies from a low of $8.6 million to a high of $10.6 million with a median cost scenario of $9.6 million ($638/kW). This is compared to a monopile cost of $6.3 million per turbine ($423/kW).

Figure 12. Monte Carlo simulation results showing the ranges or probable cost outcomes derived from the probabilistic estimate



In addition, a simulated sensitivity analysis was performed to determine the most influential costs impacting the variance of the total foundation costs. The results indicated that labor costs have the greatest impact to the overall variability of the forecasted final foundation cost. A simulated sensitivity analysis was performed by component fabrication and the overall impact to the final cost variance of the tripod foundation. The foundation center hub piece was determined to be the most impactful to the final cost of the foundation due to its construction complexity.

Automated systems such as 3DCP and/or automated formwork systems were identified in Phase I as technologies with the potential to improve costs and production of the concrete fabrication process. Specifically, 3DCP was proposed for further investigation in Phase II. Using theoretical unit cost data ($/calendar year) provided from a parallel study sponsored by the California Energy Commission investigating the application of 3DCP on the fabrication of towers to support land-based wind turbines, an analysis was performed to compare costs. The unit costs were adjusted to reflect East Coast concrete supply chain market costs. Because 3DCP is an unproven technology in this application, the simpler components were analyzed to compare the cost to fabricate the components with 3DCP versus traditional methods. The tripod concept's concrete fabrication process consists of the parallel casting of 13 total components plus three concrete suction piles. The six least complex tripod foundation components and the three concrete suction buckets were analyzed and compared. The results indicate there is potential for approximately $500,000 in cost savings per foundation with application of 3DCP, resulting primarily from the fabrication of the concrete suction piles. However, as an emerging industry, 3DCP has a very limited history of cost data at production scale, and further research must be performed to validate and calibrate the theoretical costs for 3DCP components in the fabrication of the tripod foundation components.

Risks to project execution were identified, including logistical risk due to construction personnel and material deliveries, and facility site characteristics such as ground bearing capacity and existing site conditions. While there are many risks with these large projects, there are also opportunities to improve efficiency, cost, and production of the concrete tripod foundation design concept. For example, further design optimization can allow for reduced material and assembly costs and increased production rates. In addition, if multiple projects are delivered in sequence on the East Coast, economies of scale can be leveraged to improve cost efficiencies in port manufacturing facilities and labor production improvements. Finally, automated formwork and manufacturing systems and/or 3DCP can be explored for incorporation into the concrete fabrication process to increase efficiency and production rates and reduce labor costs.

6.6 Update CapEx and LCOE Estimates

In Subtask 6.6, NREL updated the CapEx and LCOE estimates for the refined substructure design and down-selected transportation and installation methods. The most significant changes from the analysis performed in Phase I included a down-selection from multiple potential components to a single, more refined design along with a more detailed, bottom-up cost estimate to manufacture the concrete tripod.

The original LCOE estimate used the default port parameters in the ORBIT model along with approximate site conditions as a default site had not yet been selected. The down-selection process involved selecting a representative fabrication port for the concrete tripods (South Brooklyn Marine Terminal) and a representative marshaling port (New London State Pier). The project team also identified the New York Bight Wind Energy Areas as having a significant portion of the designated offshore wind areas with water depths greater than 50 m, the target depth for the concrete tripod. These updated assumptions led to several updates in the ORBIT site configurations. The down-selection process eliminated the concept of sequential tripod and wind turbine installation, leaving only the concept where the foundation and turbine are assembled together at quayside and are wet towed to the project site. NREL incorporated NETSCo's estimated costs of the IPS into the capital costs of the project and made minor adjustments to the day rates of individual vessels in the ORBIT model. NREL updated the capital costs of the concrete tripod from $526/kW to $661/kW following the updated bottom-up cost analysis by UNL in Subtask 6.5. This corresponds to a cost of $9.9 million per concrete tripod.

In the original LCOE study, the monopile and the concrete tripod had comparable LCOE values of $74.80/MWh. The updated results show a slight decrease in the monopile cost to $74.50/MWh, due to the lower average wind speed used at the site (requiring a smaller monopile to withstand turbine thrust loads). The LCOE of the tripod solution showed a moderate increase to $76.70/MWh primarily due to the increased capital costs of the concrete foundation relative to the original estimate. The updated LCOE value of $76.70/MWh is 3% higher than that of the monopile at the site in question. Within precision of this type of study, the LCOE costs for the two foundations are about the same. The installation costs of the concrete tripod are still significantly lower than the monopile scenario, as no WTIV is required, which helps to offset the higher capital cost of the structure. There were some additional impacts from a more specific port and project site location, which primarily impact installation times, but the majority of the cost differential was due to the higher CapEx of the concrete foundation.

As discussed in Subtask 3.2, the concrete tripod presents additional potential advantages to the project. There are few WTIVs available in the global market that can install a 15-MW wind turbine, and these vessels will have commitments to non-U.S. projects. Eliminating the need for a WTIV in a project installation therefore helps to reduce the risk of delays. The installation approach of the concrete tripod shifts more operations to quayside, which reduces health and safety risks for workers, limits the exposure to weather delays at sea, and decreases the overall installation time. The ability to construct the concrete foundation at a U.S. port can help to reduce dependencies on international supply chains, which also have commitments to other countries' offshore wind targets. Finally, the concrete tripod can be installed without pile-driving, which can potentially impact marine life including endangered species in the installation area. Several caveats to the results of this LCOE analysis are:

- The cost estimates for the concrete tripod were developed using bottom-up, site-specific construction quotes with cost inputs from a major U.S. construction firm, whereas the monopile foundation costs are derived from broader industry cost trends that make up the default cost rates in ORBIT. A similarly detailed cost estimate of monopile and jacket foundations that are built in the United States should be conducted and may impact the findings.
- The installation process times used in the study are also sourced from industrywide data and may change as the industry moves to 15-MW wind turbines. Again, a more detailed assessment of how installation processes at sea may change for larger machines is warranted.
- NREL used aggregated port costs for the monopile and tripod scenarios ($2 million per month for the monopile, $4 million per month for the concrete tripod to account for additional equipment, such as cranes, to assemble the turbine). Obtaining more specific pricing estimates for the port space and equipment rentals would also provide more detailed insight into the differences in costs.
- NREL assumed no difference in O&M or decommissioning costs for the different foundations in the ORBIT model, although the different materials and designs may lead to different operational or end-of-life (or repowering) strategies, which could have significant impacts on LCOE.

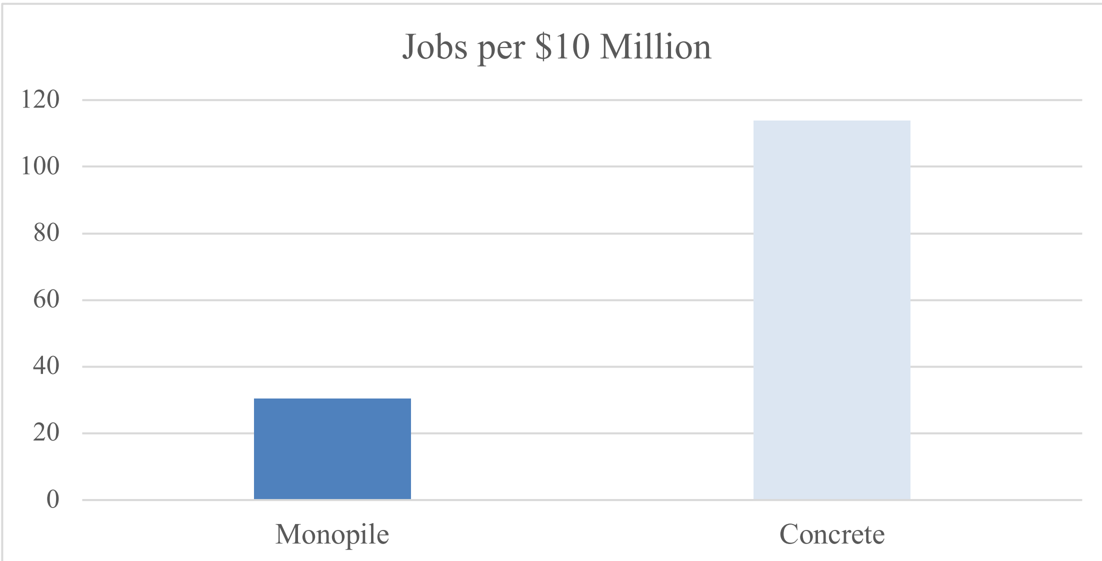
6.7 Regional Economic Benefits Analysis

In Subtask 6.7, WSP and NREL evaluated and compared the economic impact of modular concrete offshore wind foundations with monopile foundations in New York State and in the United States. For each technology, the project team developed an estimate of the number of jobs supported for each $10 million spent on manufacturing, assembly, and installation of the foundations.

The economic impact assessment was conducted using NREL's Jobs and Economic Development Impact (JEDI) model. Inputs to the model included the cost estimates for concrete foundations developed as part of other tasks in this study, monopile cost estimates developed with the ORBIT cost model, local spending assumptions, and assumptions about plant size and location. The JEDI model considers interindustry relationships and relationships between industries and households in New York State and in the United States to develop an estimate of the total number of jobs supported by spending on wind foundations, including on-site installation jobs, manufacturing jobs, supply chain effects, and induced jobs. For the purpose of this project, the JEDI model was customized to add the option to conduct a screening-level analysis of the impact of a concrete substructure using the same methodology as the monopile substructure already included in JEDI. Only spending that takes place within the region of analysis will have a direct impact on that region's economy. Furthermore, multiplier impacts estimated with the JEDI model include only impacts that are triggered by spending within the region. Therefore, local spending assumptions are a key input to the JEDI model. The JEDI with modular concrete option includes local spending assumptions that are based on regional purchasing coefficients, which are estimated by IMPLAN and reflect the proportion of a study area's demand for a commodity that is supplied by producers located within that area. Regional purchasing coefficients were based on historical industry data. They are industry-specific and region-specific and reflect the proportion of a material input that is purchased within the region. During the development of the JEDI model with modular concrete option, the IMPLAN regional purchasing coefficients are aggregated to reflect the aggregated industries developed to match the modular concrete and monopile spending patterns. Concrete substructures are assumed to use 100% U.S.-sourced manufacturing content, while monopile structures are assumed to rely almost entirely on imported materials to represent the case in which the monopiles cannot be secured from a domestic factory. For both monopile and concrete structures, an estimated 68% of assembly and installation spending is assumed to take place in the United States, with a majority of that spending assumed to occur in New York.

Figure 13 shows the total job impact in the United States per $10 million of foundation spending for monopiles and concrete foundations. The total number of jobs include on-site jobs, manufacturing jobs, jobs supported by supply chain effects, and jobs supported by household spending of workers (induced effects). While concrete foundations cost more than monopile foundations, on a national level for each $10 million of spending on foundations, concrete results in more than triple the number of jobs than monopiles. Within New York State, for each $10 million of spending on foundations, concrete results in more than double the number of jobs than monopile foundations. Therefore, while concrete foundations are a more expensive investment than monopiles, they lead to better jobs and economic outcomes per dollar spent.

Figure 13. Total employment impact in the United States per $10 million of foundation spending, by foundation type



The economic assessment in this report is a screening-level analysis. The JEDI model uses IMPLAN input-output multipliers, which are based on historical data about the average concrete industry in New York State. Based on the estimates developed in Subtask 1.5, the new concrete fabrication method is expected to be more labor-intensive than in the average New York State concrete industry. Therefore, the job impact of concrete foundations developed for this report may be underestimated.

The current analysis assumed that 20 percent of monopile spending would occur within New York State based on historical data for the steel industry. If, in the future, monopiles would be manufactured in New York or elsewhere in the United States, the impact of monopolies would increase. Conversely, if monopolies are purchased from abroad and local spending would be 0%, then the model overestimates the impact of monopiles.

A more detailed economic study is required to reflect the demand for labor and materials generated by the new foundation technology and 3DCP. The detailed study would use a bottom-up approach to estimate the workforce requirements that are specific to the technology type instead of using input-output multipliers based on historical data about the average concrete industry. This direct estimate would be combined with a more detailed analysis-by-parts methodology to estimate indirect impacts to the lower-tier supply chain.

7 Plan Follow-On Structural Testing, Field Demonstration, and Certification Activities

Task 7 plans follow-on testing, demonstration, and certification activities required for commercializing the modular concrete support structure and heavy-lift vessel alternative system. The scope includes updating the risk assessment (Subtask 7.1), creating preliminary test plans and estimating the costs for laboratory structural tests (Subtask 7.2), and conducting utility-scale demonstration activities (Subtask 7.3).

7.1 Update the Risk Assessment

In Subtask 7.1, RCAM updated the assessment of outstanding technology risks and most beneficial risk mitigation measures related to the modular concrete support structure and transportation and installation systems identified and tracked throughout the project. The risk assessment methodology followed the NREL Risk Management Framework developed for marine and hydrokinetic devices. The NREL framework covers projects of any technical readiness level and all risk types (e.g., technological risk, regulatory risk, commercial risk) over the development cycle. Technological risks for the concrete foundation are described here, and commercialization and regulatory risks are addressed in Subtask 7.4.

A total of 38 risks were assessed and categorized based on the general concept, construction and 3DCP, suction buckets, launch and transport to the marshaling site, and transport and installation. Each risk was assigned a total risk score calculated as the product of the likelihood of occurrence and the potential impact to cost and schedule. The team expects that all risks can be effectively mitigated and managed.

The highest scoring risk for the general concept was turbine repair and refurbishment. Replacing such large, heavy components likely requires a wind turbine installation vessel, which would cause a long schedule impact if the WTIV was not available. This risk can be mitigated by designing the support structure to accommodate heavy-lift vessel operations.

The greatest quantity of high-scoring risks were those associated with the construction methodology due to the inclusion of the risk and uncertainties associated with the low technology readiness level (TRL) of 3DCP. However, aside from the 3DCP risks, the only high-scoring technical risk associated with the construction methodology is the limited availability of skilled construction labor. The primary mitigation measures for this labor availability risk are to incorporate automated construction methods such as 3DCP and partner with workforce development programs. In addition, development of concrete production for other offshore wind products such as 3D concrete printed anchors or energy storage systems could provide a beachhead market and a path for the engagement, organic growth, and development of the local concrete supply chain in the offshore wind industry.

Seven risks were identified associated with suction buckets; however, all suction bucket risks except one have low risk scores. The primary risk associated with all suction buckets (both steel and concrete) is that the suction buckets do not fully embed during installation as expected. The most promising risk mitigation measures for mitigating the embedment risk is using subsea vibratory hammers on top of the suction pile or using hammered piles instead of suction buckets.

The team identified 13 risks associated with launching, marshaling, transport, and installation of the foundation, three of which have risk scores of 10 or greater. The risks associated with wet towing and submerging the foundation have the highest scores. These risks score highly because the consequences of a seakeeping failure could potentially be severe, such as overturning or sinking the foundation. These risks have been addressed in detail in prior tasks. In general, these risks are carefully accounted for and mitigated in the foundation design and seakeeping analysis activities, tank testing activities, and technology qualification processes.

The risk framework developed here provided a useful system for reducing the risks of industry failures and advancing the development of new technologies for other marine energy applications such as fixed-bottom offshore wind support structures. By addressing uncertainties, the framework increased the likelihood of the successful development of RCAM's offshore wind support structure. The risk assessment and mitigation measures, along with other project deliverables, form a risk management plan needed for commercialization of the modular concrete foundation and for informing follow-on testing activities.

7.2 Laboratory Testing and Future Research and Development Planning

In Subtask 7.2, the project team planned laboratory testing and future research and development for the concrete modular foundation, including structural testing of the foundation, 3DCP research and development, and testing the installation procedures in a wave basin.

The design of all components of a structure must satisfy requirements in a "code of practice" or be validated by tests and/or analyses that are deemed by the responsible jurisdiction to provide sufficient evidence of satisfactory performance. The structural testing of conventional construction methodologies and 3DCP construction is necessary where the structural design is outside of acceptable design codes or where confirmation testing is deemed necessary to qualify the technology. The project team defined four testing programs that address the most critical structural risks: (1) a large-scale and small-scale component testing program to validate the integrity of the connection between the support structure and the suction buckets, (2) a test of a concrete suction bucket embedded in sand to validate the failure behavior of the bucket, (3) a wall joint testing program to validate water tightness during service, fatigue, and ultimate loading, and (4) a testing program of a model of the entire substructure in a wave tank to validate hydrodynamic computer modeling of the force levels and scour behavior under various sea states. Test setups were conceptually designed for each program in consultation with leading structural testing laboratories. The cost of the campaigns, not including design labor, specimen fabrication, or customized equipment costs, is estimated at $2.35 million with the majority of the cost ($1.65 million) being for large-scale suction bucket structural testing. The total costs with the design labor, fabrication expenses, and customized equipment is estimated at $3 million.

The scope of scale tank/basin testing includes model engineering, fabrication, and test planning. The scope of tests carried out are static tests, a dynamic tow test, wave testing, wind-scale testing, and installation simulation. The design advancement and engineering tasks are estimated to cost $120,000. The model-scale testing cost estimate with scour testing is estimated at $330,000 which results in a total cost of $450,000 for the required design advancement and testing campaigns. The additional design work for the IPS and testing campaign are expected to require approximately 9 months and 3 months to complete, respectively, with an additional lead time for facility access of approximately 1 year.

7.3 Utility-Scale Pilot Test Planning

In Subtask 7.3, the project team considered project findings and inputs from the stakeholder workshops and advisory discussions to develop a preliminary pilot testing plan needed to address technical risks that must be addressed to commercialize the concrete modular foundation. The scope of utility-scale pilot test plan includes fabricating and testing the independent pontoon system, manufacturing and assembling a full-scale (15-MW) tripod foundation, and demonstrating the transport and installation of the 15-MW foundation using the IPS.

The original testing and demonstration plan in the project scope of work, which was drafted nearly 3 years ago in June 2019, included field testing a subscale foundation sized to support the DOE/NREL 600-kW or DOE/NREL 1.5-MW wind turbine on land. At the time, the land-based demonstration was viewed as a lower-cost, intermediate step needed to de-risk the offshore concrete modular foundation. However, several important changes have occurred, and learnings obtained during the project have motivated the team to instead plan for construction and marine testing of a full-scale (15-MW) engineering prototype (a pilot) in lieu of land-based field testing using a smaller land-based wind turbine.

A key motivating factor for this change was the substantial acceleration of offshore wind energy deployment targets since 2019. At the time, the emerging U.S. offshore wind energy industry had only five offshore turbines installed, representing 0.3 GW of capacity, and the domestic offshore wind market was projected to grow very rapidly to 18.6 GW by 2030. The pipeline of U.S. projects has nearly doubled since then to over 35 GW. In addition, larger turbines have been announced since 2019 that include larger 14-MW to 16-MW models from Siemens Gamesa, GE, Vestas, and Ming Yang that make even larger 20-MW turbines seem more likely in the near future. Furthermore, new offshore wind lease areas, wind energy areas, and planning areas in deeper waters have been designated in the United States. These increases in deployment goals, turbine size, and water depth have increased the urgency of developing heavy-lift vessel alternatives such as the tripod foundation and accelerating time to market.

A second motivating factor for testing in the ocean is that the project team has identified that the primary technology risks for the offshore modular foundation cannot be addressed by testing on land. Land-based testing is most useful for testing the manufacturing and structural performance of the foundation, which the team views as low-risk activities that do not warrant the investments required for land-based testing.

The primary technical risks facing the concrete modular foundation are associated with the wet towing and installation of the foundation at the site. The wet towing and installation risks are best addressed by wave basin validations followed by full-scale verification and demonstration of the pilot in an ocean environment. The construction risks (hoisting, moving, and formwork processes) are also best addressed by manufacturing a full-scale (15-MW) prototype in a representative port environment rather than a 600-KW to 1.5-MW prototype in an inland location. For this reason, the land-based testing originally proposed does not warrant the high cost and time required; instead, an accelerated full-scale offshore pilot test plan has been developed.

The wet towing and installation systems will be addressed by fabricating and testing a full-scale prototype of the independent pontoon system using approved incline procedures to determine intact stability compliance. The IPS full-scale prototype final design will be developed following results derived from the laboratory/model testing and following rules for classing and building barges from a recognized

International Association of Classification Societies organization. Fabrication of the pontoon will follow a traditional barge construction model, and that could be built in a shipyard in the northeastern United States. Launching of these pontoons will be performed in typical shipbuilding fashion, which will be using a dry dock or launch way. Jacking system fabrication requires careful consideration. The jacking legs will be tubular, which requires rolling large-diameter steel, similar to but smaller than a monopile. Other than the new facility in Baltimore that is currently being configured to fabricate monopiles, most of the facilities that could fabricate the jack-up legs are in the Gulf of Mexico, so most likely these will need to be transported to the Northeast.

The incline test involves causing the vessel to heel to small angles by moving weights transversely across the deck and observing the angles of inclination. The incline test could be performed at the fabrication shipyard, which would have most of the equipment and personnel required for the test. Following the incline tests, each of the units will go through a stand-alone sea trial. The IPS connection system and disconnection system will first be conducted quayside in calm waters to provide crane and fabrication yard support to address any unexpected issues. This test will be an operational test, conducting a full connection and disconnection of each IPS. Following this test, the complete unit (substructure and IPS) will be towed to a predetermined area in a semi-sheltered marine location, with enough water depth to lower the unit just beyond the 14-m draft, to ensure stability at this depth. An operational test of the jacking system will also be performed at this location. For this part of the test, three tugboats will be used for towing, positioning and standby, and a full ballasting crew to operate the ballast system.

Most seakeeping, stability, and survivability testing for the substructure will be addressed within the laboratory/model testing phase. The only prototype full-scale testing projected for the substructure will be the ballasting and deballasting, and the testing will be done in conjunction with the jacking system testing. A full-scale incline test for the substructure may be required by class; however, given that this is a fixed-bottom structure and that stability is only required for transportation and installation, it is possible that this requirement could be waived.

The cost estimate for the marine testing activities is approximately $365,000. This cost should be considered rough-order-of-magnitude estimates with a variation of ±30%. This cost estimate is specifically for the additional cost required for testing and excludes the $6.5 million in costs to design or fabricate a single IPS unit.

Construction and assembly risks are less severe due to the conventional methods selected for construction, but they also require verification. The construction and assembly risks are best addressed by manufacturing a full-scale prototype in a representative port environment. Testing of the hoisting, moving, and formwork activities can be performed as integrated tests during the full-scale fabrication of a 15-MW pilot prototype as an integrated development effort. The efforts and costs for the additional tests will be relatively small compared to the development of the pilot-scale prototype, adding approximately 3% to 5% to the overall cost to fabricate a pilot prototype. In addition, the testing activities can be performed in parallel to or integrated with the pilot-scale fabrication (approximately 18 months) to avoid extending the duration of the construction process. Other recommended full-scale testing includes concrete placement consolidation and production rate testing.

The large mass of the concrete foundation will require that the pick points on the foundation and ground bearing pressure at the port be verified prior to project implementation. In addition to analyzing and verifying pick point capacity, the hoisting equipment will exert great pressure on the ground of the port fabrication facility during critical lifts. The existing ground bearing capacity at each of the proposed port facilities selected should be tested. Ground conditions are unique to each port facility, and the site investigations and testing will need to be site-specific to each port facility.

The first pilot prototype is expected to cost four to five times the foundation costs achieved in commercial production, or $30 million to $40 million, depending on a variety of factors including the fabrication and assembly location and availability, risk tolerance, and interest of the construction contractor. Accordingly, the additional cost for designing the additional testing for hoisting, moving, and formwork activities is expected to be between 3% of $30 million to 5% of $40 million, or $1 million to $2 million.

7.4 Plan Commercialization

Subtask 7.4 developed a commercialization plan and product development road map for the modular concrete foundation and heavy-lift vessel alternative concept. The report contains market and competitiveness assessments, a standards-based design certification and testing plan, U.S. manufacturing plan, intellectual property/licensing plan, capital funding plan, and cost estimates for a comparable steel jacket foundation.

The general market outlook and need for fixed-bottom foundation solutions and heavy-lift vessel alternative has remained strong and has increased since the NOWRDC-funded project began in 2020. RCAM believes the most promising target market are coastal states in the Northeast without monopile manufacturing facilities. New York and Massachusetts are particularly attractive markets for the concrete tripod foundation. Together, Massachusetts and New York have over 20,000 MW of offshore wind pipeline potential, a substantial portion of which is in water depths ranging from 45 to 60 m. This target market is valued at over $17 billion of installed foundations, assuming an installed cost of the tripod foundation of $12.7 million.

RCAM's primary value proposition for customers (wind plant developers) is an unmatched scoring advantage in local-content merit criteria for state-issued offshore wind solicitations and the elimination of WTIVs for deployment. In the longer term, RCAM's modular concrete support structure can also support larger turbines and be deployed in more regions including deeper water and more extreme, hurricane-prone sites. RCAM's support structure also avoids monopile hammering noise and reduces the footprint required for concrete foundation manufacturing.

On a cost basis alone, RCAM's concrete modular foundation is projected to be cost-competitive today with existing foundations in RCAM's target market. The CapEx of the modular concrete foundation is projected to be more expensive than monopiles, but significantly less expensive than jackets. The team estimated the cost of steel jackets using three different approaches with results ranging between $14.6 million and $18 million for the assumed New York deployment. The team has the most confidence in a rough-order-of-magnitude cost estimate (also known as Class 5 estimate, −50% and +100%) for fabrication/installation of a jacket-type foundation performed by WSP USA that estimated steel jacket costs of $16.5 million in total, which includes $3 million for installation and $13.5 million for domestic fabrication of the jacket, transition piece, and piles. The cost estimate assumed:

- Deployment to New York Bight west of Long Island in a water depth of 50 to 60 m.
- Jackets for 15-MW turbines.
- 67 turbines (1,005-MW plant).
- 2022 cost per installed jacket (no turbine or external platform/transition pieces are assumed in the estimate).

Although the cost of RCAM's foundation is higher than monopiles, the higher capital cost is somewhat offset by the reduced cost of turbine installation due the elimination of the heavy-lift installation vessel, resulting in an estimated LCOE increase of approximately 3% compared to a conventional monopile at the project reference site.

RCAM's modular concrete support structure combines proven low-cost concrete, transportation, and suction pile foundation technologies into an innovative offshore support structure system. The NOWRDC project has advanced the TRL of the integrated solution (the foundation and installation system) from TRL 1 to TRL 3. A standards-based design certification and testing plan, U.S. manufacturing plan, intellectual property/licensing plan, and a capital funding plan are presented to advance the technology to TRL 7, which is the deployment of a full-scale system in an operational environment.

The goal of RCAM's certification plan is to ease the use of the modular concrete foundation and WTIV-alternative in the project certification of a commercial wind plant. RCAM's plan entails three primary phases, including approval in principle, certification through technology qualification, and integration in the project certification process.

RCAM is partnering with a range of domestic and international engineering services and research partners to develop its support structure technology. The company has been working to develop partnerships with customers such as offshore wind developers and strategic partners such as engineering procurement and installation contractors to co-develop its foundations.

In the short term, RCAM will continue to pursue the partnerships needed to manufacture modular concrete foundations using proven, low-risk precasting manufacturing methods. RCAM will partner with engineering procurement and installation contractors, ports, and marine transport companies to manufacture and sell its foundations directly to one or more strategic customers (offshore wind developers), depending on their level of investment and role in developing the technology.

In the longer term, RCAM will incorporate more advanced, automated concrete manufacturing methods to fabricate concrete support structure modules that will reduce costs and incorporate more complex support structure geometries that reduce labor and materials. A key part of this plan is to continue the development of RCAM's 3DCP anchors and energy storage systems.

RCAM is building a patent portfolio around its 3D concrete printing products and the related manufacturing and transportation/installation methods. The patents primarily help ensure that RCAM's support structure manufacturing business will have "freedom to operate" (does not infringe on the patent rights of others) and that RCAM can attract the funding required to sustain operations and advance its concrete manufacturing methods and capabilities for all of its offshore products, including the fixed-bottom support structure.

In general, RCAM anticipates that its strategic engineering procurement and installation partner will price the support structure at approximately $15 million per installed foundation. RCAM will license its technology to strategic partners at a rate of approximately up to 2% of the installed cost of the foundation, resulting in $300,000 of revenue per modular foundation or $20 million per 1-GW wind plant.

RCAM is pursuing a commercialization plan that develops and demonstrates its modular concrete support structure and heavy-lift vessel alternative at full scale (15-MW class turbines) in 2028. RCAM projects approximately $67 million of additional funding will be required to bring the foundation and IPS to TRL 7.

RCAM's funding strategy uses nondilutive state and federal funding for early stages of development, followed by larger private investments from strategic partners. $5.1 million of investments are required for the detailed design, structural testing of the foundation, and wave basin testing of the IPS system. Approximately $20.3 million is required to develop a full scale IPS system. RCAM plans to further explore a multi-use approach for the IPS to leverage this investment.

RCAM will continue to develop its 3D concrete printing approach for concrete anchors and energy storage systems, which will create new cost reduction opportunities for the foundation prototype. 3DCP has the potential to reduce the cost of commercialization by approximately $20 million by eliminating the formwork required for the first prototype, reducing port footprint, automating construction, and leveraging equipment and capabilities developed for RCAM's other offshore wind and energy products. In addition, 3DCP is projected to reduce the cost of each foundation by half a million dollars during commercial production.

8 Stakeholder/Advisory Panel Comprehensive Workshop

RCAM held a stakeholder/advisory group comprehensive workshop on March 3, 2022, to obtain stakeholder and subject matter expert feedback on the results of the Phase I and Phase II project tasks. The primary objectives of the stakeholder workshop were to communicate project results to stakeholders and potential commercialization partners and obtain stakeholder feedback on results and commercialization plans. The workshop was held virtually because several attending organizations were still restricting travel due to the COVID-19 pandemic. However, the virtual meeting venue provided the team with the opportunity to invite a more diverse and larger audience than originally planned. Key stakeholders invited included approximately 60 offshore wind developers, potential supply chain partners, project stakeholders, subject matter experts, and project team members. In addition, the Zoom meeting forum allowed for the workshop to be recorded for future reference.

The workshop successfully achieved the objectives of communicating the project results to over 36 project stakeholders and potential commercialization partners. The most important feedback from the workshop includes the following findings:

- A key discussion question asked of attendees was whether the Jones Act wind turbine installation vessel (WTIV) “bottleneck” is still one of the main hurdles for U.S. offshore wind energy development. Significant discussion regarding the Jones Act WTIV bottleneck was held. The concept of wet towing the turbine fully assembled was encouraged. There was agreement that the WTIV bottleneck is still a major concern due to limited vessel availability in the United States.
- Marshaling port space was also identified as a major U.S. concern. The University of Delaware suggested we read their new journal article that reports insufficient available or planned marshaling area to support U.S. offshore wind energy targets (Parkison and Kempton 2022).
- The fully assembled deployment configuration was confirmed to be an attractive solution.
- A major international offshore wind developer, to whom this is the first time the project was presented, expressed they are optimistic about the solution.
- 3D concrete printing can help address port footprint constraints and geometry changes.
- There were notably no objections to the team’s assertion that the non-LCOE benefits of the solution are important.

In addition, the virtual forum, which was arranged like a panel with discussion periods after each speaker, seemed sufficiently effective for engaging a variety of stakeholders despite the virtual forum. The virtual forum enabled participation of a large and more diverse audience including some from Europe. However, adding an hour to the meeting length to make the total meeting length four hours would have been helpful for covering the commercialization details more fully and obtaining additional feedback.

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