Representative Project Design Envelope for Floating Offshore Wind Energy: A Focus on the California 2023 Federal Leases

Aubryn Cooperman, Michael Biglu, Matt Hall, Daniel Mulas Hernando, and Stein Housner

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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Disclaimers

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List of Acronyms

ACP	American Clean Power
AHTS	anchor-handling tug supply (vessel)
BOEM	Bureau of Ocean Energy Management
CAISO	California Independent System Operator
cm	centimeter
COP	Construction and Operations Plan
in.	inch
ft	foot
GW	gigawatt
HDD	horizontal directional drilling
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
km	kilometer
kV	kilovolt
m	meter
MW	megawatt
nmi	nautical mile
NREL	National Renewable Energy Laboratory
PDE	project design envelope
ROV	remotely operated vessel
RPDE	representative project design envelope
TLP	tension-leg platform

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1 Introduction

Offshore wind energy development in the United States has to date consisted of fixed-bottom wind turbines in the Atlantic Ocean off the east coast. Planned areas for future offshore wind development include deeper waters offshore Maine, Oregon, and California. In these areas where water depths drop off much more steeply, projects cannot use fixed-bottom technology. The use of floating technologies with buoyant substructures in deeper waters will result in a different physical footprint that could impact offshore wind plant design, installation, and operations.

The Bureau of Ocean Energy Management (BOEM) is the lead federal agency for planning and leasing areas for offshore wind on the United States Outer Continental Shelf. Once an area is leased, the company then develops and submits to BOEM a Construction and Operations Plan (COP). This plan contains the proposed design specifications that all permitting agencies use to evaluate a project. A project design envelope (PDE) approach is a project plan that adheres to a reasonable range of project design parameters. BOEM gives offshore renewable energy lessees the option to use a PDE approach when submitting a COP and issued draft guidance to this effect in 2018 (BOEM 2018). There are benefits to allowing lessees to describe a reasonable range of project designs in a COP given project complexity, the unpredictability of the environment in which it will be constructed, and/or the rapid pace of technological development within the industry. Many leaseholders off the U.S. east coast have utilized the PDE approach in their COPs. No COPs exist for floating offshore wind projects in United States federal waters.

A representative project design envelope (RPDE) provides estimates of the scale and number of components in a floating offshore wind facility when there is a need to describe impacts but there is not yet a PDE to evaluate. This report describes RPDE recommendations developed by the National Renewable Energy Laboratory (NREL) for floating offshore wind energy projects. In the development of these recommendations, we considered industry feedback from offshore wind farm developers in the California lease areas and a practical range of technology options that may be deployed, accounting for major physical constraints and technical readiness.

Section 2 of this report presents the RPDE, and Sections 3 and 4 present four scenarios that illustrate some of the differences between technologies that could be used offshore California, as well as descriptions of the typical installation processes that are expected to be used for floating offshore wind farms. These two sections are intended to provide greater depth and context for the information presented in the RPDE, but do not represent a comprehensive analysis of the design space and possible installation methods. This report does not represent real or proposed projects. It is an attempt to capture a realistic range of technical specifications and layouts of floating wind facilities given the water depths, wind characteristics, and distance from shore of the lease areas offshore California.

2 Representative Project Design Envelope

BOEM issued five leases for offshore wind energy development on the Outer Continental Shelf of California (U.S. Department of the Interior 2022). The water depths between 500 and 1,300 meters (m) (1,800–4,200 feet [ft]) in these lease areas make fixed-bottom technology infeasible, so projects on the California coast will use floating technology. Floating offshore wind is an emerging technology deployed in demonstration and pilot projects. Global deployment of floating projects was just over 120 megawatts (MW) in 2022, compared with 59,000 MW of fixed-bottom offshore wind (Musial et al. 2023). Operational floating wind energy projects use several different substructure designs, and more varied designs have been proposed.

The purpose of this section is to assess the likely range of values for the physical design elements of floating offshore wind development in the California lease areas. An RPDE provides estimates of minimum and maximum values for project design parameters that are relevant for assessing environmental impacts. Table 1 presents the RPDE for the California offshore wind lease areas. The representative project is an offshore wind power plant comprising multiple wind turbines, one or more electric substations, support structures, moorings, and power cables, installed within an area of up to 325 square kilometers (km^2) (80,418 acres) with water depths between 540 and 1,300 m (1,760–4,300 ft) off the coast of California. We provide more detailed information about each of the design elements and define terms in Subsections 2.1 through 2.6 following Table 1.

Table 1. Representative Project Design Envelope

Element	Project Design Element	Typical Range
Plant Layout	Plant capacity	750–3,000 MW
	Number of wind turbines	30–200
	Turbine spacing	920 m–3 km (0.5–1.6 nautical miles [nmi])
	Watch circle radius	Up to 350 m (1,150 ft)
	Capacity density	3–9 MW/km^2
Wind Turbines and Substructures	Turbine rating	15–25 MW
	Turbine rotor diameter	230–305 m (750–1,000 ft)
	Total turbine height	260–335 m (850–1,100 ft)
	Turbine installation method	A floating substructure, with turbine preinstalled at port or sheltered location, towed out to site by a towing vessel group/a floating substructure towed to site, with turbine installed at site by a wind turbine installation vessel or heavy-lift vessel.
	Substructure type	Semisubmersible, barge, or tension-leg platform (TLP); conventional spar may not be feasible but other ballast-stabilized designs may be considered.
Moorings	Mooring line configuration	Taut, semi-taut, or tension leg; catenary moorings are possible but less likely.
	Mooring arrangements	3–12 mooring lines per turbine or substation; shared-anchor arrangements are possible, shared-mooring arrangements are possible but less likely.
	Mooring line materials	Synthetic fiber rope (polyester, high-modulus polyethylene, nylon), steel chain, steel wire rope, steel or fiber tendons

		(e.g., carbon fiber). May also include buoyancy modules, clump weights, load reduction devices, and other accessories.
	Anchor type	Depending on soil type and mooring configuration: suction caisson, helical anchor, plate anchor (vertical load anchor or suction-embedded plate anchor), dynamically embedded (torpedo) anchor, driven pile, drilled pile, micropile, gravity anchor; drag embedment anchor is possible but less likely.
	Anchor material	Steel or concrete; drilled piles and micropiles may use grout.
	Seabed footprint radius	50–2,600 m (160–8,500 ft)
	Seabed contact area	200–300,000 m^2 (0.05–75 acres)
Array Cables	Total array cable length	1–5 km (0.5–2.7 nmi) average per turbine; individual cables may be up to 20–30 km (10.8–16.2 nmi) in some circumstances.
	Array cable diameter	14–25 cm (5.5–9.8 inches [in.])
	Target array cable depth	At least 60 m (200 ft) below water surface.
	Array cable configurations	Cables and mooring lines may be suspended in the water column, laid on the seabed, or buried. Suspended cable configurations can include but are not limited to lazy wave, catenary, steep wave, or suspended U.
	Array cable installation methods	Cable-lay vessel, possibly assisted by a remotely operated vessel (ROV) and/or construction support vessel.
	Cable protection types	Dynamic cables: accessories for cable protection may include bend stiffeners, dynamic bend restrictors, buoyancy modules, sleeves, seabed tethers, anchors or any other combination of protection means as determined by the site-specific design. Seabed: protection could include burial, rock dumping or mattresses.
Export Cables	Number of export cables	2–8
	Total export cable route length	35–400 km (19–270 nmi) per cable (offshore)
	Export cable voltage	Up to 525 kilovolts (kV) (DC) or 420 kV (AC)
	Export cable diameter	12–36 centimeters (cm) (4.7–14 in.)
	Export cable configuration	Dynamic cable between a floating substation and the seabed, with a transition joint to static cable for remaining length/static cable between a subsea substation and cable landfall.
	Export cable seabed disturbance (width)	Up to 13 m (43 ft) per cable, or cable diameter if not buried
	Export cable spacing	2–3 times the water depth on at least one side of a cable to provide repair access, minimum 50–200 m (160–660 ft) between adjacent cables.
	Target export cable burial depth	1–3 m (3–10 ft). Burial may not be required along full cable route depending on water depth, seabed conditions, vessel traffic and other factors considered in a cable burial risk assessment.
	Export cable installation methods	Trenchless: horizontal directional drilling (HDD), direct pipe, micro-tunnel, jack and bore.

		Trenched: open cut, direct burial. Tools and vessels: cable-lay vessel, ROV, cable plow, hydro plow, jetting sled, vertical injector, tracked trencher.
	Cable protection types	Dynamic cables: accessories for cable protection may include bend stiffeners, dynamic bend restrictors, buoyancy modules, sleeves, seabed tethers, anchors, or any other combination of protection means as determined by the site-specific design. Seabed: burial, rock, concrete mattress (at crossings).
Offshore Substations	Number of offshore substations	1–6
	Offshore substation substructure type	Floating: semisubmersible, barge, TLP, spar Emerging technology: subsea substation
	Offshore substation seabed footprint radius	50–2,600 m (160–8,500 ft)
	Offshore substation seabed contact area	200–300,000 m^2 (0.05–75 acres)
Onshore Facilities	Transmission points of interconnection	Various potential points of interconnection may be considered.
	Ports	Potential staging and integration ports: Port of Humboldt, Port of Long Beach, Port of Los Angeles. Additional ports in California that could support component storage, laydown, fabrication, or operations and maintenance: Crescent City Harbor District, Port of Stockton, Port of Benicia, Port of Richmond, Port of Oakland, Port of San Francisco, City of Alameda, Port of Redwood City, Antioch, City of Pittsburg, Pillar Point Harbor, City of Morro Bay, Diablo Canyon Power Plant, Port San Luis, Ellwood Pier, Port of Hueneme, and Port of San Diego. Ports outside of California may also support component manufacturing, storage, or installation.
Vessels	Construction vessel types	Vessel types used during construction may include survey vessels, heavy-lift vessels, wind turbine installation vessels, cable-lay vessels, anchor-handling tug supply vessels, offshore construction vessels, feeders, crew transfer vessels, and service operation vessels. See Section 4.1 for descriptions of these vessel types.
	Transit locations	Construction vessels most often transit to the area from Texas and Louisiana through the Panama Canal or from across the Pacific Ocean if outside the United States.

2.1 Plant Layout

2.1.1 Plant Capacity and Capacity Density

The capacity of an offshore wind project, or plant, is derived from the combined nameplate capacity of multiple wind turbines installed in a designated area. The main elements of an offshore wind plant are illustrated in Figure 1. The plant capacity represents the maximum power output (in megawatts or gigawatts) of the power plant. The plant capacity is influenced by several factors that have not yet been determined in the California lease areas, such as offtake agreements, wind turbine rating, layout and density of turbines, and site-specific obstacles to turbine placement. To estimate total plant capacity without these inputs, we use capacity density, which measures the power-generating capacity installed within a specified area.

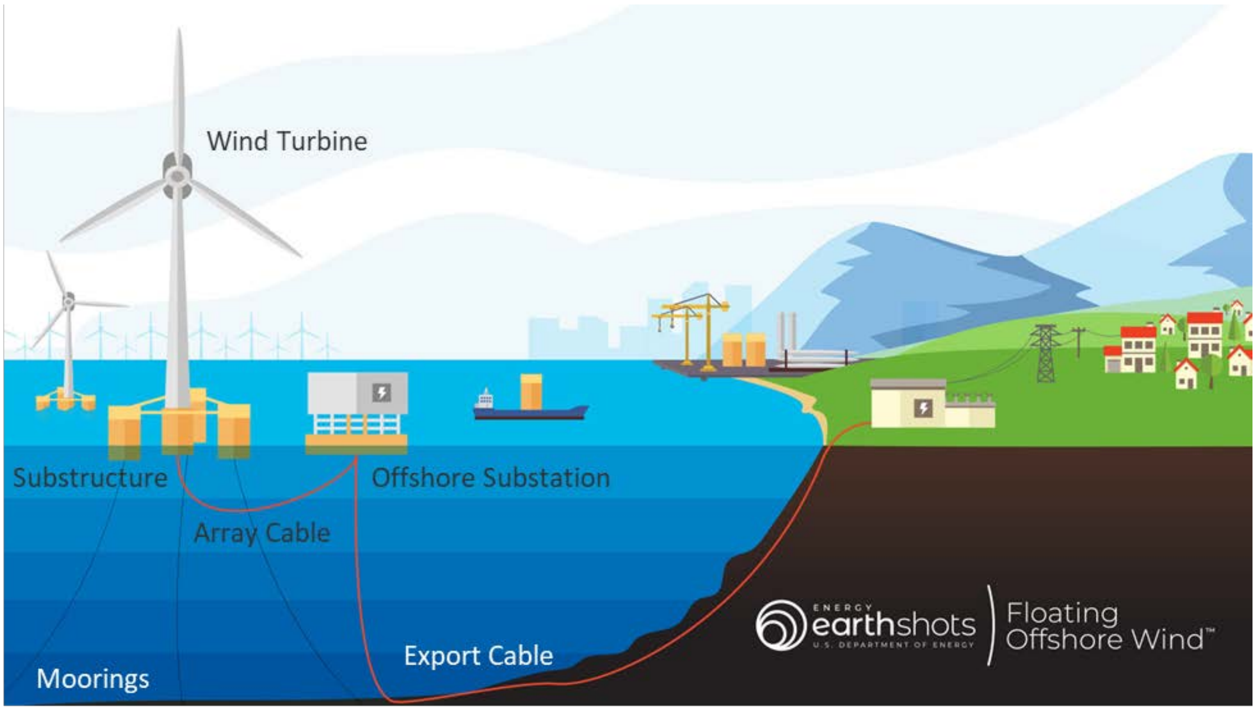

Figure 1. Floating offshore wind plant

Image from U.S. Department of Energy, with labels added by authors

We considered a range of possible capacity densities based on planned offshore wind projects on the U.S. Atlantic coast. A comparison of 17 fixed-bottom projects found capacity densities between 2 and 9 MW/km^2; however, densities close to the lower bound of 2 MW/km^2 were only observed in areas where a fixed turbine spacing was prescribed (Mulas Hernando et al. 2023). We consider 3 MW/km^2 to be a reasonable lower bound of capacity density because BOEM and NREL estimated 3 MW/km^2 in the delineation of the California leases (Cooperman et al. 2022). The planning process for offshore wind leasing areas, such as offshore Oregon (BOEM 2024), now considers an updated capacity density of 4 MW/km^2 (Musial et al. 2023). The maximum plant capacity considered in this report is 9 MW/km^2. This is consistent with the upper bound reported by Mulas Hernando et al. (2023) based on public announcements of offshore wind plant capacity and development area. Among projects with approved COPs, the maximum capacity density is closer to 8 MW/km^2.

To determine the plant capacity, the capacity density (3–9 MW/km^2) is multiplied by the total lease area. The California lease areas range from 256 km^2, for the smallest of the five leases, to 325 km^2, which represents the largest California lease. The resulting estimated total plant capacity of a California offshore lease used in this report is between 750 MW and 2,925 MW. In Table 1, we round the maximum value to 3,000 MW to avoid an appearance of false precision resulting from these approximations.

2.1.2 Wind Turbine Spacing and Number

Wind turbine spacing will need to incorporate many considerations, including energy production, navigation, and array layout. Agreements regarding the utilization of the area for other ocean activities (e.g., fishing) may influence the design, but the parties involved have not yet reached a consensus that could be used to inform this report. Based on the wind distribution in the California lease areas, which is highly unidirectional, spacing may be wider along the prevailing northerly wind direction with tighter spacing along the opposite axis. Spacing wind turbines between 4 and 10 rotor diameters apart (Cooperman et al. 2022) would result in a minimum distance of approximately 0.9 km (0.5 nmi) and a maximum distance of 3 km (1.6 nmi). The number of wind turbines was estimated by dividing the total plant capacity by the maximum and minimum turbine ratings, discussed in Section 2.2, resulting in a range of 30 to 200 wind turbines per lease area.

2.1.3 Watch Circle Radius

An additional consideration for the layout of floating wind turbines is their range of motion at the water surface. This range of motion—known as the watch circle—is determined by the mooring system's resistance to platform offsets caused by wind, waves, and currents (Figure 2). The radius of the watch circle corresponds to the maximum horizontal displacement of the floating platform. Depending on the mooring system design, the distance between the central position and the maximum displaced position may not be the same in all directions (in other words, the watch circle may have a noncircular shape). Floating offshore wind turbine arrays have not been deployed in depths equivalent to the California lease areas anywhere in the world. We therefore used internal engineering design studies as the primary source of estimates of the watch circle dimensions. Based on watch circle sizes reported in these studies, an upper bound on expected watch circle radii is 350 m, whereas smaller watch circle radii on the order of 100 m are likely in many cases. Watch circle size is expected to roughly scale with depth for a given type of mooring system. The 350-m-radius watch circle upper bound would be for the greatest depths of 1,300 m in the California leases. These watch circle radii describe the extreme offsets in an intact condition. Failure of a mooring line could result in a much larger offset, especially for nonredundant mooring designs. Floating offshore wind array design is an active area of research, and site-specific designs for projects in California may arrive at new solutions that balance mooring system footprint, redundancy, and platform displacement.

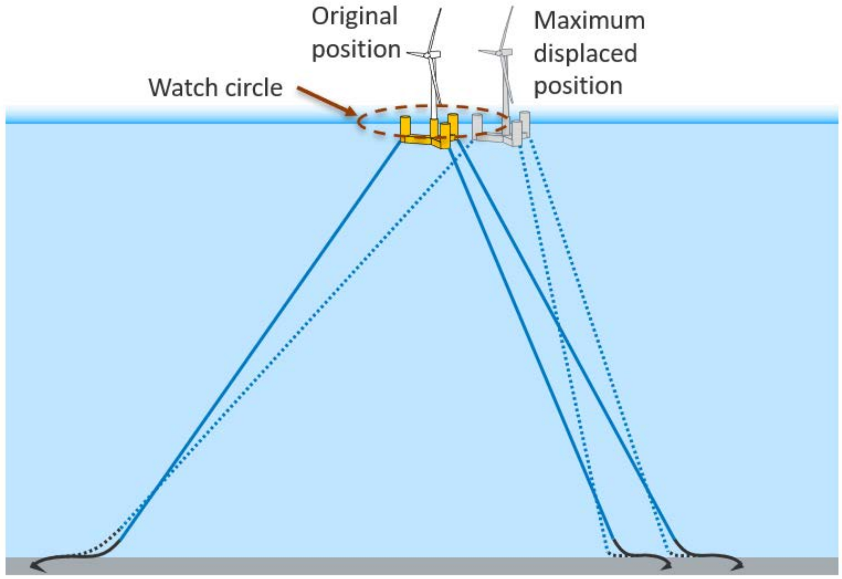

Figure 2. Watch circle for a generic semi-taut mooring system

2.2 Wind Turbine Generators

2.2.1 Turbine Rating, Rotor Diameter, and Height

The size and rating of offshore wind turbines have increased noticeably over the last two decades, and even larger models are under development (Figure 3). Constraints in the supply chain, vessel capabilities, and port infrastructure are a current challenge and may limit continued upscaling (Musial et al. 2023). Offshore wind turbines installed in 2022 had an average rating of 7.7 MW, but manufacturers announced the development of turbines with ratings up to 22 MW. Turbines with ratings of 13 MW were installed in commercial-scale U.S. Atlantic offshore wind farms in 2023 (Vineyard Wind 2023; GE Vernova 2023). Leaseholders in the California offshore wind lease areas are considering a range of turbine ratings between 15 and 25 MW. Assuming that the specific power (rated capacity per rotor-swept area) remains similar to current offshore wind turbine models, rotor diameters for these turbines would be approximately 230–305 m (750–1,000 ft). With a tip clearance of approximately 30 m from the mean sea level, this results in a total turbine height of 260–335 m (850–1,100 ft) above the still water level.

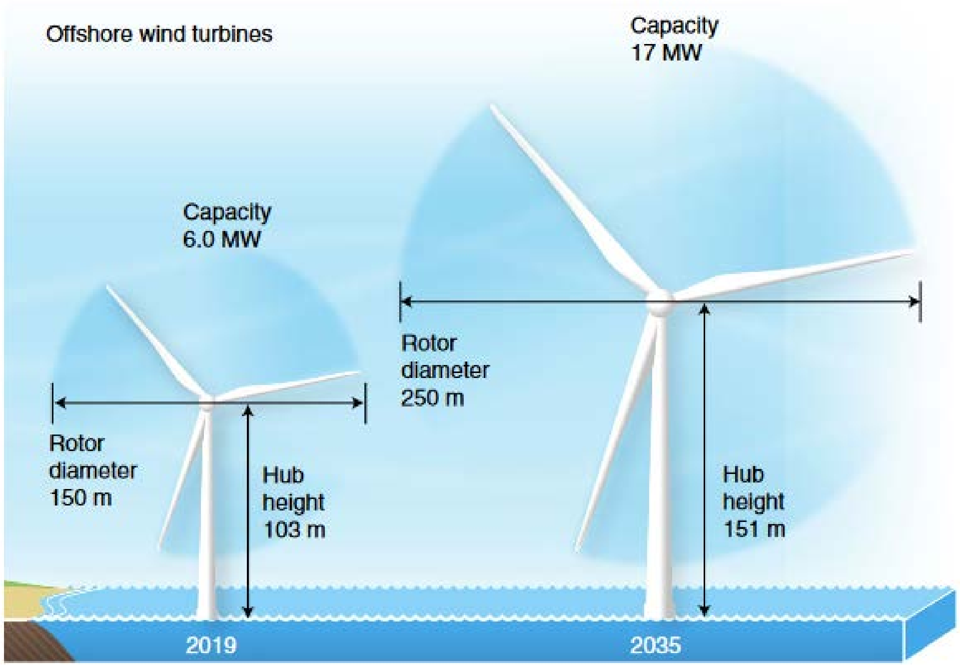

Figure 3. Evolution of wind turbine rating and size over time.

Source: Wiser et al. (2021)

2.2.2 Substructure Type and Installation Method

In the California lease areas, water depths are more than 500 m (1,640 ft), and offshore wind plants will require floating substructures. Floating substructure designs rely on a combination of three stability types: ballast, buoyancy, or moorings. Figure 4 illustrates three conventional substructure types: spar, semisubmersible, and TLP. Floating substructures are in use for commercial oil and gas operations but are considered an emerging technology (Horwath et al. 2020; Edwards et al. 2023) for commercial-scale floating offshore wind. In 2022, there were approximately 86 MW of operational offshore wind projects using semisubmersible or barge substructures and 38 MW using spars (Musial et al. 2023). There were no operational offshore wind TLPs in 2022. TLP and semisubmersible substructures appear feasible in California; however, the California coast does not have sheltered deep waters (such as fjords) suitable for assembling traditional spar designs in the way that has been demonstrated in Europe.

Figure 4. Examples of floating substructure types (left to right): spar, semisubmersible, TLP.

Illustration by Joshua Bauer, NREL

The floating substructures shown in Figure 4 are not the only options. Newer technologies that are variations of the conventional substructure types or combinations of the three stability types may be suitable and utilized in California. More than 20 different types of floating substructures have been demonstrated (Edwards et al. 2023), and many more designs have been proposed. Some designs have a shallower draft in port and then tilt or deploy ballast to reach a deeper draft during installation. Other proposed designs combine the buoyancy of semisubmersibles with the mooring tension of TLPs to achieve faster deployment. Steel and/or concrete are typically the primary structural materials for floating substructures. The choice of substructures for California wind farms will be influenced by many factors, including site conditions, port and manufacturing facilities, cost, and installability.

The method for installing floating substructures differs depending on the substructure design. One typical method is to assemble the substructure and integrate the wind turbine onto the substructure within a port or sheltered harbor before towing the wind turbine and substructure to the wind plant site, where they are hooked up to moorings and intra-array cables. Alternatively, floating-to-floating assembly could take place at sea; however, this would require a vessel with sufficient crane capacity as well as advanced motion compensation to carry out the installation process.

The draft—or distance from the water surface to the bottom of the substructure—of a floating substructure that is towed from a port must be compatible with the harbor channel depth (11–15 m or 38–50 ft at California ports considered for staging and integration) (Trowbridge et al. 2023). During installation, the draft may be increased to enhance stability by various means, including mooring system tension or by adding ballast (e.g., seawater, sand, rock, or iron ore). Operational drafts vary with the specific design, but indicative values for conventional designs are 80 m (260 ft) for a spar, 20 m (65 ft) for a semisubmersible, or 30 m (100 ft) for a TLP (Porter and Phillips 2016; Edwards et al. 2023).

2.3 Moorings

2.3.1 Mooring Line Configuration, Arrangement, and Materials

Floating offshore platforms are anchored to their positions within the offshore wind lease area through mooring systems. Mooring lines can consist of steel chain, synthetic fiber rope, steel wire rope, or tendons made from steel or synthetic fibers. Tendons—tensioned, vertical mooring lines—are used for TLPs, whereas the other floating platform types use rope and/or chain in a taut, semi-taut, or catenary configuration. Although catenary moorings have been demonstrated in floating offshore wind projects at water depths of 60–300 m, these configurations are less likely to be used in the California lease areas because they would entail very long lengths of large-diameter chain, making them prohibitively heavy for the floating platforms and requiring a large seabed area to accommodate an anchor circle radius that could be several times the water depth. The size and quantity of chain required would approach the limits of current manufacturing capacities. The number of mooring lines depends on the level of redundancy desired in the mooring system and the selected trade-off between component sizes and quantities. Existing examples of floating wind turbine platforms have included between three and eight mooring lines (Edwards et al. 2023); platforms for floating substations could potentially use up to 12 lines for additional stability and redundancy. Mooring lines for multiple wind turbines may connect to a single anchor in a shared-anchor configuration. Shared-mooring configurations, in which mooring lines run directly between adjacent wind turbines, are also possible but less likely because these concepts have not yet been demonstrated.

2.3.2 Seabed Footprint Radius and Contact Area of Mooring Systems

The mooring system seabed footprint radius and seabed contact area are important metrics in Table 1. The seabed footprint radius varies widely between mooring configurations, as illustrated in Figure 5. The distance on the seafloor from a TLP anchor to the center of the turbine position can, at a minimum, be approximately 50 m (160 ft). The radius of taut, semi-taut, and catenary moorings depends on the water depth, the angle of the mooring line, and the physical properties of the mooring line or chain. For the water depths in the California lease areas, we consider 2,600 m (8,500 ft) to represent a reasonable upper bound on the horizontal extent of the mooring footprint.

The choice of mooring configurations also affects the seabed contact area. Taut mooring lines and TLP tendons do not contact the seabed, so the contact area is only as large as the anchor footprint. We estimated the minimum area of seabed contact in this scenario to be approximately 200 m^2 in total based on three suction pile anchors each contacting the seabed within a circle 10 m in diameter. Semi-taut and catenary moorings include a horizontally oriented segment that lies on the seabed and moves in response to floating platform motions and currents acting on the moorings. We estimated the maximum seabed contact area in this scenario to be 300,000 m^2. This maximum value assumes 12 mooring lines, each with 1,000 m of chain on the seabed that has a lateral range of motion of 50 m at the touchdown point and is fixed at the anchor. The seabed contact area and mooring footprint radius are shown in Figure 5 for a semi-taut mooring configuration (illustrating maximum values) and a TLP configuration (illustrating minimum values).

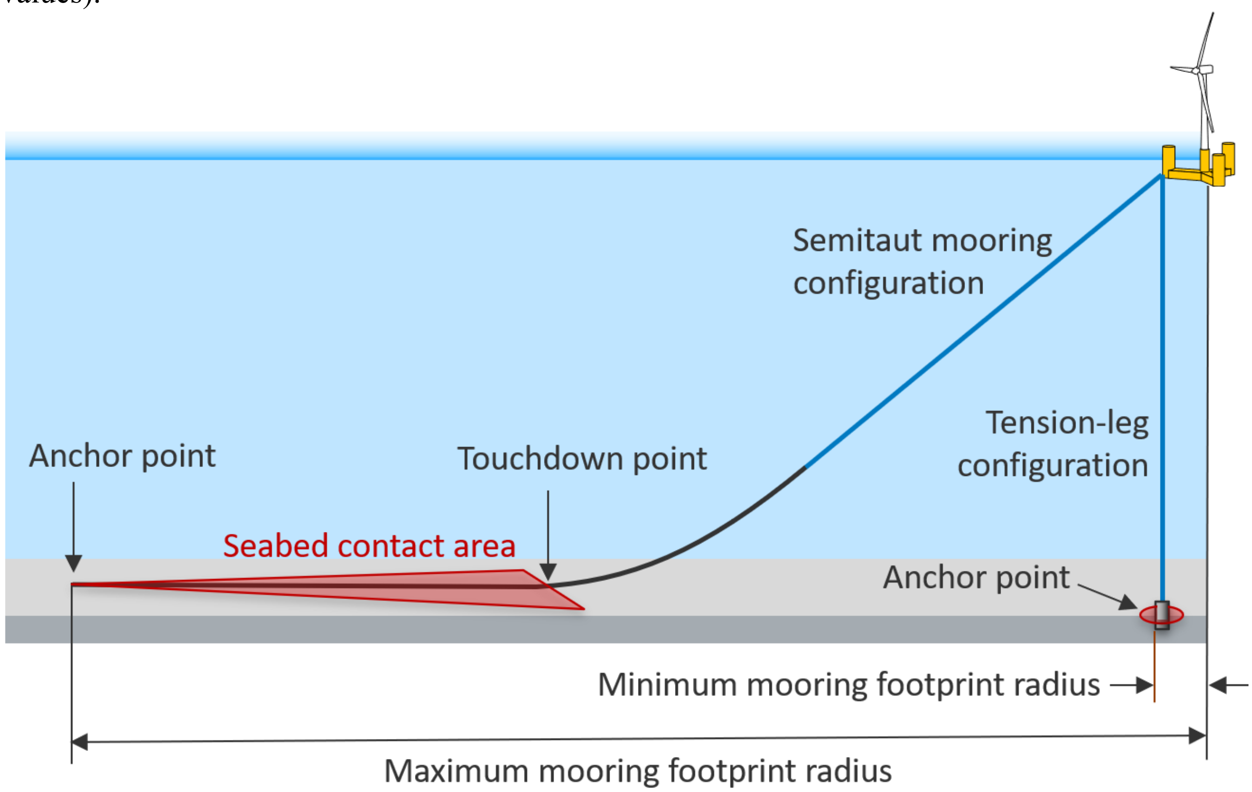

Figure 5. Seabed contact area and footprint radius illustrations for a single anchor and mooring line in a semi-taut configuration and a TLP configuration. Blue lines indicate synthetic rope and black lines indicate chain segments.

2.3.3 Anchors

Anchors fix the mooring lines to the seabed. Multiple types of anchors will be feasible for most projects. Common anchor types include drag embedment anchors, suction caissons or piles, vertical load anchors, drilled piles, and gravity or deadweight anchors (Figure 6). These are typically made of steel, but concrete could be a viable option as well. Although drag embedment anchors have been used in floating wind energy demonstration projects, the use of drag embedment anchors in the water depths in the California lease areas would require seabed footprint radii of multiple kilometers due to the method of seabed resistance that drag embedment anchors use. In addition to water depth, the choice of anchor will be influenced by local soil type, seismic risk, mooring configuration, cost, and installation logistics. Anchoring needs for floating wind turbines in areas with seismic activity are ongoing research topics. Depending on the anchor type selected, anchors would be embedded on the order of tens of meters but may require deeper embedment to be below near-surface sediment layers that are susceptible to liquefaction or slumping.

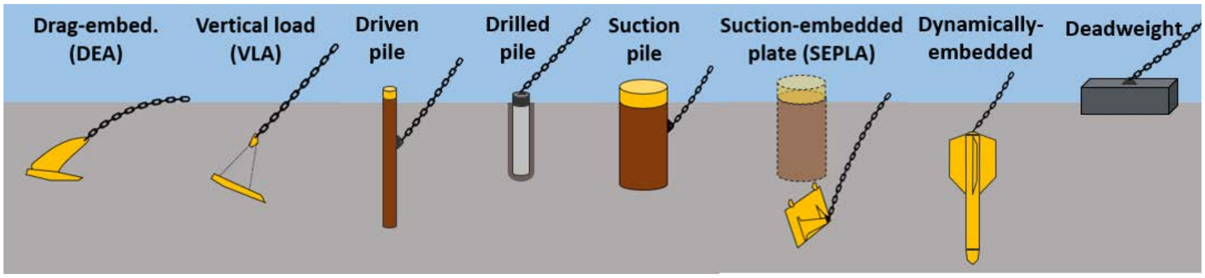

Figure 6. Types of anchors

New anchor technologies have the potential to reduce cost and risk. Shared anchors are anchors with multiple mooring line attachments that connect to multiple floating offshore wind platforms that would reduce the total number of anchors in a wind farm and reduce cost. Helical anchors use multiple long, slender pile anchors with helices attached that are relatively easy to install, are low weight, and provide high load capacity. The effects that these anchors have on the seabed are not expected to vary significantly from conventional anchor types.

2.4 Array and Export Cables

Offshore wind plants require array (collector) cables between individual wind turbines and the offshore substation(s), and one or more export cables to connect the offshore substation(s) to the electric grid. Cable segments that run between a floating platform and the seabed or another floating platform must be designed to withstand the loads and motions associated with being suspended in the water column; these are called “dynamic” cables. Static cables can be used for segments that lie at or under the seabed, connected to the dynamic segment via a transition joint. Dynamic cables are typically double-armored to have greater fatigue resistance, tensile strength, and bending stiffness than equivalent static cables and have correspondingly higher cost. Dynamic cable systems also include ancillary equipment to protect the cable and maintain the desired profile through the water column (Figure 7). Dynamic cables can have a variety of profiles, depending on the application, the most common of which is the lazy wave shape shown in Figure 7. The water depths in California are much deeper than existing floating wind farms and may prompt the use of more compact “steep wave” profiles, catenary profiles, or array cables that are fully suspended between turbines, without any static portion touching the seabed (Figure 8). In these cases, different cable profiles would be used, likely following a U or W shape. Although dynamic cables have been used for oil and gas platforms and offshore wind pilot projects, the technology has not yet been demonstrated at the voltage level that would be required for a commercial-scale offshore wind plant export cable (Corewind 2020; Huang, Busse, and Baker 2023).

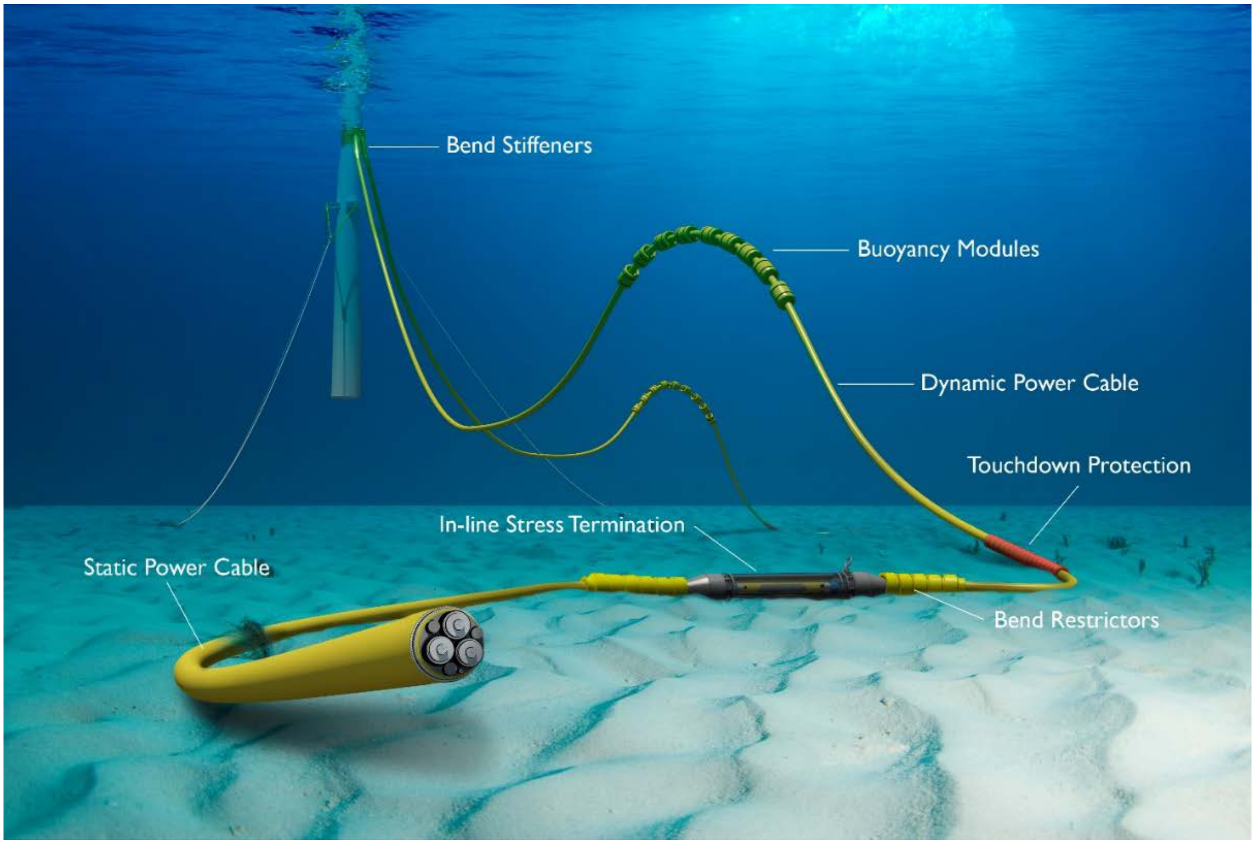

Figure 7. Dynamic subsea cable system components

Illustration by Joshua Bauer, NREL

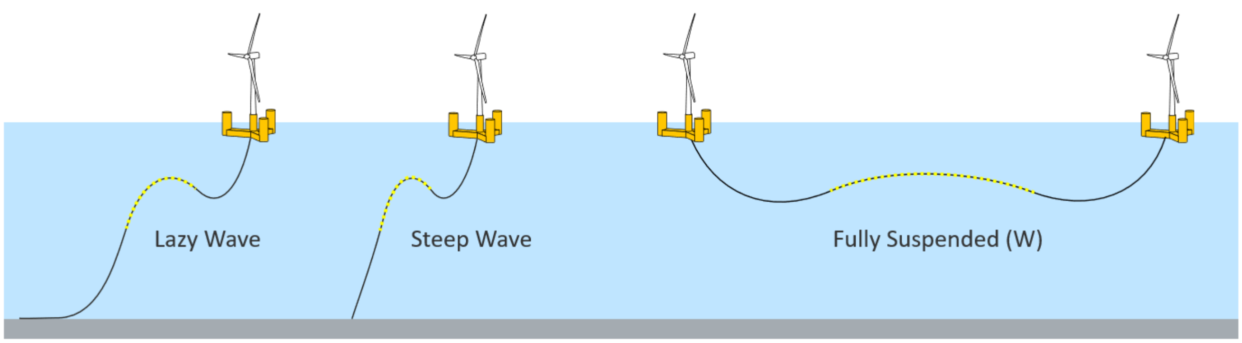

Figure 8. Three common dynamic cable profile shapes

2.4.1 Array Cable Configurations and Depth

Array cables are the cables that carry power from each turbine to the point where energy is collected for export. Array cables connect individual turbines to each other in strings and connect the strings to an offshore substation. A typical configuration is a radial—or daisy chain—arrangement, in which each turbine is connected to two adjacent turbines in series with one end at the substation. Although this often results in a cost-effective design, a cable failure can lead to several turbines no longer being supplied with power (American Clean Power [ACP] 2024).

Another option is to connect the turbines in a ring, which has the advantage of diverting the power in the other direction if one cable fails. Alternative configurations could also be considered to increase redundancy or reduce material use (Marcollo and Efthimiou 2024).

In fixed-bottom offshore wind plants and floating offshore wind demonstrations to date, array cables were laid on the seabed or buried. This configuration is well-tested and suitable for situations in which the horizontal distance spanned by the cable is much larger than the water depth. In the California lease areas, the water depth can be approximately the same as the distance between adjacent wind turbines, and in some cases may be greater. Suspending array cables in the water column using buoyancy modules or other cable accessories may be considered as a method to reduce the total length of cable required and minimize electrical losses. The depth at which cables may be suspended is yet to be determined, and it would depend on factors such as mechanical properties of the cable, the layout design, protection of the cable from wave action, and navigation considerations. Seabed lay of array cables is also possible.

2.4.2 Array Cable Length and Diameter

The length of cable required for each turbine depends on the array configuration. With turbine spacings of 900 m (0.5 nmi) or more, at least 1 km (0.5 nmi) of cable per turbine will be needed to allow for the cable depth and relative motion between turbines. An upper bound on the average cable length of approximately 5 km (2.7 nmi) per turbine accounts for wide turbine spacing, watch circles, and seabed cable lay at the maximum water depth of 1,300 m. Individual cable segments may be longer or shorter than this average length, depending on the site-specific layout. For instance, the connection between a string of turbines and the offshore substation could be up to 30 km (16 nmi) depending on the array layout. The cable size for each section depends on the rating and number of upstream turbines feeding into the specific cable (ACP 2024). The latest standard for array cables in Europe is a 3-core design in the 72.5-kV class, which complies with IEC 63026 (ACP 2024). Dynamic 66-kV cables in use today have diameters of 14–20 cm (5.5–8 in.); 132-kV dynamic cables will likely be available by the 2030s and could have diameters up to 25 cm (9.8 in.) (Carbon Trust 2022).

2.4.3 Array Cable Installation and Protection

Specialized cable-lay vessels will be required for array cable installation, with support from other vessels that may include tugs, construction support vessels, or ROVs. If array cables are buried, the route will need to be cleared before cable lay begins. The potential for interaction between cable-lay activities and mooring installation should also be considered. Protection methods for cables on the seabed include burial, mattresses, and rock dumping. Seabed tethers and anchors may be used near the point of touchdown. If array cables are suspended in the water column, options for protection include bend stiffeners, dynamic bend restrictors, and protective sleeves (Offshore Wind Scotland 2024). When developing the wind plant layout, the relative motion of turbines within their watch circles must be considered to ensure that the array cables do not incur displacements beyond their design capabilities. Another design consideration to reduce risk is to avoid placing array cable hang-offs near boat landings (ACP 2024).

2.4.4 Export Cable Configuration, Voltage, and Diameter

Both high-voltage alternating current (HVAC) and direct current (HVDC) technologies could be considered for offshore export systems. HVAC export cables are typically three-core cables, with voltage between 220 kV and 420 kV for a 1-gigawatt (GW) wind plant. HVDC export cables are currently available at 320 kV, and 525-kV cables are being developed (ENTSO-E 2024). Configuration options for HVDC circuits include:

- Asymmetric monopole: one HVDC cable with a metallic return and a converter at each end of the cable
- Symmetric monopole: two HVDC cables and a converter at each end of the circuit
- Bipole: two HVDC cables and an optional metallic return with two converters in series at each end of the circuit.

The selection of HVAC or HVDC cable also affects the cable diameter. Three-core HVAC cables have larger diameters, up to 36 cm (14 in.), whereas single-core HVDC cables with cross-linked polyethylene insulation can have a smaller diameter of 12 cm (4.7 in.). The distance to shore, the related costs and electrical losses and the plant capacity are the most important factors for choosing an HVAC or HVDC system. An HVDC system is more likely to be suitable for longer export cable distances (more than 70–100 km) and larger plant capacities (more than 800–1,000 MW).

2.4.5 Export Cable Route Length, Number, Spacing, Seabed Disturbance, and Burial Depth

The minimum distance for a cable route is the straight-line distance from the eastern edge of the Humboldt lease areas to the closest potential landfall point, approximately 35 km (19 nmi). The minimum distance from Morro Bay is approximately 60 km (32 nmi). Actual cable routes will deviate from the straight-line distance to landfall for many reasons, including locations to the grid connection, subsea topography, seabed conditions, and to avoid conflicts with other ocean users. Export cables will likely cross active faults, and additional length may be required to provide slack in case of fault rupture and displacement. Accounting for more distant potential points of interconnection and less direct cable routing to avoid obstacles gives an estimated maximum route length of 400 km (270 nmi).

The number of export cables is influenced by the total plant capacity, cable capacity, reliability considerations, and permitting. California Independent System Operator (CAISO) planning standards regulate the amount of generation that would be forced offline by a single contingency (e.g., an export cable failure); the maximum is currently 1.15 GW (CAISO 2023). Although it would be possible for an offshore wind plant with a capacity of 1 GW or less to export power via a single cable, a second cable would likely be used to provide redundancy in case of damage or failure. Typical HVAC export cables that are currently in use have a capacity of approximately 400 MW, which would result in a maximum of 8 cables for a plant capacity close to 3 GW. Fewer circuits could be used in an HVDC system, with cable capacities up to 2 GW; however, symmetric monopole or bipole configurations require two cables per circuit. In this report we assume each plant could use a total of 2 to 8 export cables. Assuming that export cables are developed independently by each leaseholder, this results in a total of 4 to 12 cables in the Humboldt region and 6 to 24 cables in the Morro Bay region.

The cable corridor width is the space required for installing and maintaining cables. In general, cable corridor widths are determined based on the number of cables, water depth, and anticipated repair methods. European guidelines for cable spacing recommend at least 50–100 m (160–330 ft) between cables (New York State Energy Research and Development Authority 2023). In deeper water depths, the primary factor affecting cable spacing is often the gap required to facilitate cable repair. The sizing of this gap is determined by the anticipated length of a cable repair bight plus a safety margin, resulting in spacing between 2 and 3 times the water depth. The repair bight is a double catenary (omega shape) in the cable profile, which is created when the two segments of cable on either side of the damaged location are recovered to a vessel where a new segment is inserted, then re-laid to one side of the original cable centerline on the seabed (ACP 2024). Offshore wind submarine cable spacing guidelines propose the possibility of laying a repair bight over an adjacent cable; however, such an approach requires the evaluation of the associated commercial and technical risks (Bureau of Safety and Environmental Enforcement 2014).

The amount of seabed disturbance associated with a cable differs between buried cables and surface-laid cables. The determination of whether to bury a cable, and the depth at which to bury it, should follow a cable burial risk assessment that considers seabed conditions, seismic risk, vessel traffic, fishing activities, permitting, and other factors. The California State Lands Commission targets a burial depth of at least 1 m (3 ft) within its jurisdiction. Cable burial depths between 2 and 2.5 m (7–8 ft) are likely to be sufficient for even the largest ships (COWI 2022). The width of seabed disturbance associated with cable burial depends on the width of the burial tool, which can be up to 13 m (43 ft) (New York State Energy Research and Development Authority 2023). Burial becomes more difficult in deep water depths and may not be feasible in some areas. Existing submarine power cables have been laid on the seabed rather than buried below water depths of 400–600 m (1,300–2,000 ft) (Ardelean and Minnebo 2015). Some power cables laid for oil and gas or transmission along the U.S. West Coast were not buried in depths of less than 400 m (1,300 ft). If the cable is not buried, the cable itself is the only cause of seabed disturbance. Like mooring lines, dynamic export cables will have a range of motion near the point where they touch the seabed, leading to a wider disturbed area in that region. A tether and anchor may be used to limit motion at the cable touchdown point.

2.4.6 Export Cable Installation and Protection

The process for installing export cable far offshore is similar to the array cable installation process and involves the same type of equipment. Near shore, additional types of equipment are used for the cable landfall, such as a flat-bottom barge, cable plow, or vertical injector. HDD to bring the power cable under the seafloor to the point of landfall is subject to the California State Land Commission's burial depth requirement, which specifies a minimum of 5 ft (1.5 m) of cover in areas with water depth between 0 and 15 ft (4.6 m). HDD of four subsea power cables offshore Newport, Oregon, reached a maximum depth of 120 ft (36 m) (PacWave 2022).

Protection methods for cables on the seabed include burial and rock dumping. If it is necessary to cross existing infrastructure, such as other power or telecommunication cables or oil/gas pipelines, the crossing should be designed carefully, considering applicable rules and guidelines and in close alignment with the owners. Typical cable crossings consist of two layers, which could be made of rock berms or concrete mattresses. The bottom layer is installed directly between the infrastructure to be crossed and the power cable, ensuring that a minimum distance—usually 12 in. (30 cm) or more, as required for heat dissipation—is maintained (Sharples 2011). The top layer is placed above the cable to keep it in position and protect it from external impacts.

For dynamic cable sections between a floating offshore substation and the seabed, options for protection include bend stiffeners, dynamic bend restrictors, and protective sleeves (Offshore Wind Scotland 2024). Seabed tethers and anchors may be used near the point of touchdown.

2.5 Offshore Substations

2.5.1 Substructure Types and Seabed Footprint

Conventional fixed-bottom foundations are most feasible for offshore substations in waters up to 60 m depth. The options for floating substructure types are similar to those for wind turbines, including semisubmersible, TLP, barge, spar, and hybrid designs. Although HVAC substations and HVDC converter platforms are established technologies for fixed-bottom offshore wind, floating versions of these platforms are still being developed. Current HVAC substations have a maximum capacity of 700–800 MW with a topside weight close to 4,000 tons and an average area of 1,000 m^2 (0.25 acres). HVDC converter station capacity can reach 2 GW, with topside weights more than 8,000 tons and an area of 8,000 m^2 (2 acres). An emerging concept for offshore substations would place the substation on the seabed, eliminating weight and motion concerns but introducing new challenges related to underwater operation (Huang, Busse, and Baker 2023).

The seabed footprint radius and contact area depend on the substructure type. We assumed the same range of potential values as for wind turbine moorings; however, substation mooring footprints will generally be larger than those of similar wind turbine moorings. The footprint of a subsea substation includes the substation equipment and cable connections, and the total area would likely fall between the minimum and maximum values for floating platforms.

2.5.2 Number of Offshore Substations

An offshore wind plant with a capacity near 750 MW could operate with a single offshore substation. Leaseholders consider up to six offshore substations to be a maximum within the existing lease areas. In the Morro Bay area where there are three leases, and we estimate a capacity range of 2 to 9 GW for those 3 leases, we estimate between 3 and 18 substations in that area. In the Humboldt area where there are two leases and we estimate a capacity range of 1.5 to 6 GW, we estimate between 2 and 12 substations.

2.6 Onshore Facilities

2.6.1 Points of Interconnection

The points of interconnection for all the California leases have not been finalized or approved. Several potential points of interconnection were identified in previous studies, including Eureka for the leases offshore Humboldt Bay and Diablo Canyon for the leases offshore Morro Bay (Zoellick et al. 2023; Cooperman et al. 2022); however, other alternatives remain under consideration. Beyond the points of interconnection, CAISO identified substantial upgrades to the land-based electrical grid that will be needed to carry power from offshore wind plants to load centers (CAISO 2024).

2.6.2 Ports

There are many different ports that could become involved in offshore wind deployment. More than 80 locations have been identified on the west coast alone (Shields et al. 2023), and ports in other regions could also supply vessels or materials. Because this RPDE focuses on California, the list of ports in Table 1 is limited to California locations; however, ports in other states may also be considered. Port facilities in California that could potentially support offshore wind activities were identified by the California Energy Commission, as required by Assembly Bill 525 (Lim and Trowbridge 2023). The ports identified in that assessment could play various roles including staging and integration, manufacturing, mooring and cable staging, and operations and maintenance. The ports of Humboldt, Long Beach, and Los Angeles were identified as potential staging and integration ports for wind turbines and floating platforms. Other California ports could support flexible laydown, manufacturing, operations, and maintenance. Additional ports outside California may also contribute to the offshore wind supply chain for projects in the California lease areas. Potential port facilities in Oregon and Washington were identified in Shields et al. (2023).

3 Scenario Analysis of Offshore Wind Plant Layout

This section introduces four scenarios to explore the range of possible impacts resulting from different plant layouts and other design options described in the RPDE. The scenarios are illustrative but not prescriptive and are categorized based on smallest and largest lease area sizes (250 km^2 or 325 km^2) and multiplied by capacity densities of approximately 3 MW/km^2 or 7 MW/km^2 to compare four plant capacities. Although 9 MW/km^2 is the maximum capacity density in the RPDE, in this section, we use 7 MW/km^2—a more moderate estimate for a commercial-scale wind farm. Different capacity densities of a plant could result from project design factors such as array layouts, turbine size, and mooring technology type, as well as the seabed characteristics and bathymetry of the lease area. The combination of two lease area sizes (250 or 325 km^2) and four capacity densities yields four scenarios detailed in Table 2.

Table 2. Offshore Wind Plant Layout Area and Plant Capacity Ranges Considered in Scenarios

	3 MW/km^2	7 MW/km^2
Small Area	(1) 250 km^2 750 MW	(2) 250 km^2 1.75 GW
Large Area	(3) 325 km^2 975 MW	(4) 325 km^2 2.275 GW

For each scenario, we created a rectangular grid layout corresponding to the prescribed area and capacity density and calculated the plant capacity and generating potential. Section 3.1 provides a detailed description of the potential scenario layouts. The results in Section 3.2 illustrate potential implications from the selection of different wind farm design options. These four scenarios are illustrative and not a proposed project. However, they do not represent all of the possible design choices within the RPDE. Offshore wind projects developed within the California lease areas will implement different designs than those illustrated here. Although we chose a rectangular layout due to its simplicity, other layout arrangements could be considered. The intent of this section is to picture and describe a range of plant layout options for the California leases without focusing on a specific site.

3.1 Scenario Layouts

Small areas are defined as individual projects within a rectangular lease area measuring 10 km in width and 25 km in length, totaling 250 km^2. Large areas maintain the same length as the small areas but extend to 13 km in width, resulting in a total area of 325 km^2.

We considered two turbine rating options for scenario development. The first option was a 15-MW turbine, aligning with near-term product offerings from turbine manufacturers including Vestas and GE Vernova (U.S. Securities and Exchange Commission 2024; Vestas 2024). The second option introduced a hypothetical 20-MW turbine representative of potential future designs. A 25-MW turbine rating is mentioned in Section 2.2 and Table 1 (maximum range in the RPDE) to avoid constraining potential turbine technology development. However, 25 MW is not considered in this scenario analysis, as this analysis is not intended to necessarily use the limit cases of the RPDE. Scenarios 1 and 4 used the 15-MW turbine, whereas Scenarios 2 and 3 used the 20-MW turbine. For each scenario, we arranged turbines on a rectangular grid with constant north-south and east-west spacings between 0.6 and 1.6 nmi. Actual layouts may use different spacings that incorporate additional considerations such as fishing or navigation corridors. The scenarios in this report are intended to illustrate the spectrum of turbine positions achievable within a high-density and a low-density lease area. However, they do not explore the limits of every parameter within the design envelope.

The scenario layout is affected by the mooring system type. The radius of the mooring system footprint determines the minimum distance a floating wind turbine can be placed from the lease area boundary (Figure 9). This decreases the developable area and may decrease the total plant capacity. For this analysis, we held the spacing fixed within each scenario to isolate the effects of mooring footprint on the turbine layout.[1] Estimates of the distances from turbine to lease area boundary as a function of water depth for different mooring types are provided in Cooperman et al. (2022) and shown in Table 3. The minimum turbine-to-boundary distance equations and values at 537 m and 1,284 m (minimum and maximum depths across the California lease areas) are shown in Table 3 and range from 100 m to almost 1,000 m. For the scenarios, we assume a constant water depth of 1,284 m. This approach highlights the maximum impact of the minimum turbine-to-boundary distance on the amount of developable area, depending on the type of mooring system used.

[1] Mooring system footprints could affect the turbine spacing. In this analysis, we assume a fixed spacing, omitting the potential impact of mooring system footprints on the turbine layout.

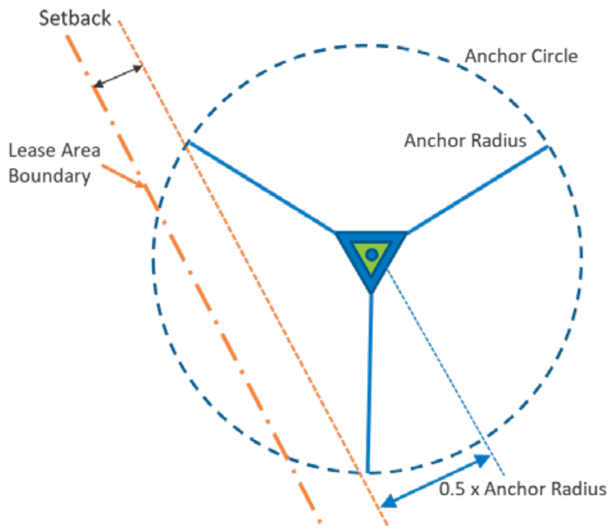

Figure 9. Schematic representation of layout constraints near the lease area boundary.

Image from Cooperman et al. (2022)

Table 3. Minimum Turbine-to-Boundary Distance for Tension-Leg Platform, Taut, and Semi-Taut Mooring Systems

Mooring Type	Minimum Turbine-to-Boundary Distance (m)	Value at 537 m Water Depth (m)	Value at 1,284 m Water Depth (m)
TLP	100	100	100
Taut (55° incline)	0.35 × water depth	188	450
Semi-taut	0.35 × water depth + 500	688	950

This results in the analysis of the plant capacity and generating performance of a total of 12 scenarios depending on area size, turbine spacing, turbine rating, and mooring system type. The layouts of these scenarios are shown in Figures 8, 9, 10, and 11.

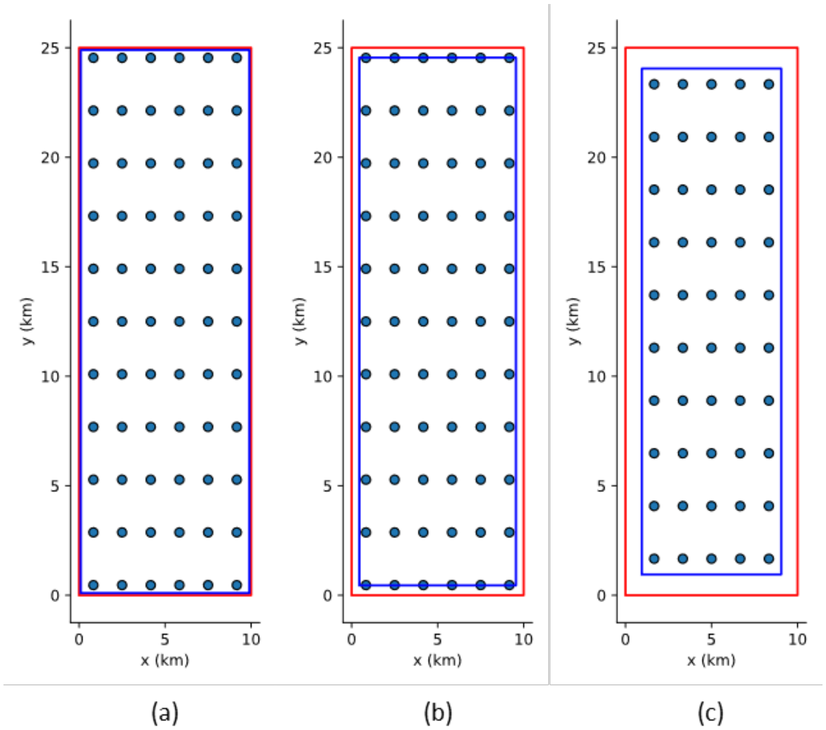

Figure 10. Scenario 1: low density, small area, 0.90 × 1.30 nmi, (a) TLP, (b) taut, (c) semi-taut

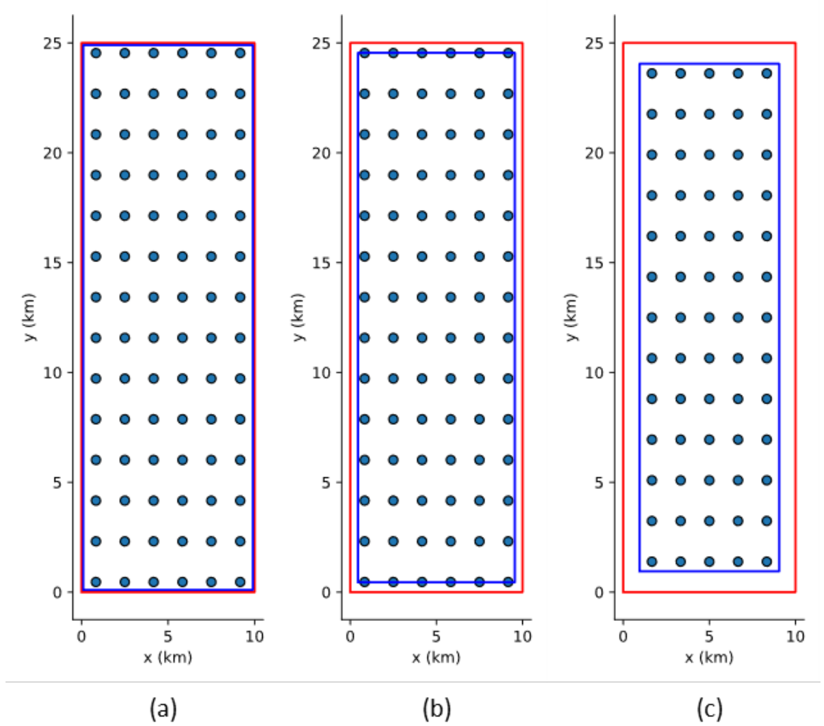

Figure 11. Scenario 2: high density, small area, 0.90 × 1.00 nmi, (a) TLP, (b) taut, (c) semi-taut

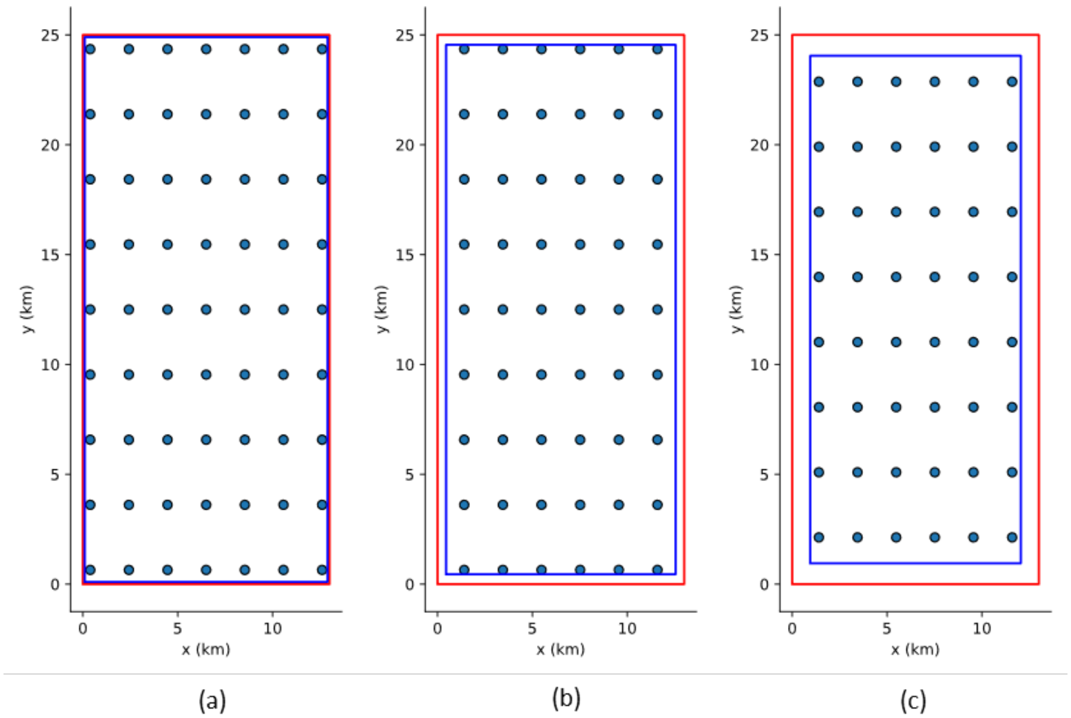

Figure 12. Scenario 3: low density, large area, 1.10 × 1.60 nmi, (a) TLP, (b) taut, (c) semi-taut

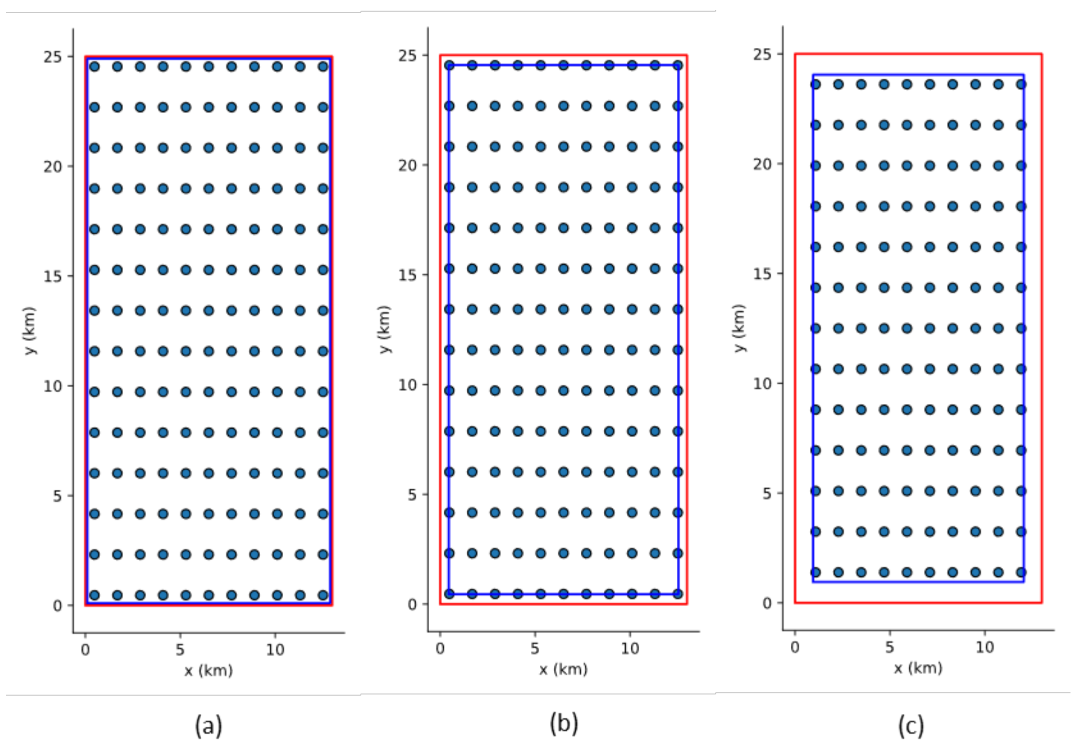

Figure 13. Scenario 4: high density, large area, 0.65 × 1.00 nmi, (a) TLP, (b) taut, (c) semi-taut

Additional variables, such as the array system configuration (suspended or buried) and the export system type (HVAC or HVDC), are also relevant for assessing impacts of a proposed layout. It is important to note that while the cable length and seabed disturbance may differ based on the array system type, and the cable corridor and platform requirements could be subject to variation based on the export system type, these factors do not impact the plant capacity of each scenario layout. Therefore, we only investigated sensitivities for these variables in Scenario 4, the high-density large area scenario, for the case of TLP moorings, which allow for the highest density.

3.2 Analysis Results

The following section provides an analysis of capacity density, plant capacity, and generating potential for the scenarios presented in the previous subsection. Net annual energy production was calculated using net capacity factors for high and low densities from Cooperman et al. (2022). The net capacity factor is the ratio of electricity output of an offshore wind plant over a specified period to its maximum possible output if the farm operated at full capacity for the same period. The results of this analysis are presented in Table 4.

Table 4. Scenario Capacity Densities and Generating Potential

Density Type	Low Density						High Density					
Area Size	Small Area			Large Area			Small Area			Large Area		
Area (km^2)	250			325			250			325		
Mooring Type	TLP	Taut	Semi taut	TLP	Taut	Semi taut	TLP	Taut	Semi taut	TLP	Taut	Semi taut
Turbine Spacing (nm)	0.90 x 1.30			1.10 x 1.60			0.90 x 1.00			0.65 x 1.00		
No. of Turbines	66	66	50	63	54	48	84	84	65	154	154	130
Turbine Rating (MW)	15			20			20			15		
Total Plant Capacity (GW)	1.0	1.0	0.8	1.3	1.1	1.0	1.7	1.7	1.3	2.3	2.3	2.0
Capacity Density (MW/km^2)	3.96	3.96	3.00	3.88	3.32	3.95	6.72	6.72	5.20	7.11	7.11	6.00
Net Capacity Factor (%)	47.7–50.2						46.5–49.4					
Net Annual Energy Production (TWh)*	4.1–4.4	4.1–4.4	3.1–3.3	5.5–5.3	4.7–4.5	4.2–4.0	6.8–7.3	6.8–7.3	5.3–5.6	9.4–10.0	9.4–10.0	7.9–8.4

*TWh = terawatt-hours

Capacity densities fall within the targeted range of 3 to 7 MW/km^2. The taut and TLP layouts have the same total capacity in each scenario. In low-density scenarios, total plant capacity ranges from 0.8 to 1.3 GW and is 100–300 MW higher for TLP and taut layouts than semi-taut layouts. The difference between TLP and semi-taut layouts is 300–400 MW in the high-density scenarios span. Capacity densities are also close to 1 MW/km^2 higher for TLP and taut layouts as compared with semi-taut mooring types in the high-density scenarios. These findings highlight the impact of mooring type choices on the number of turbine positions in each scenario and the associated variation in potential annual energy production across small and large areas under distinct spacing and turbine size selections.

We conducted an additional analysis within a high-density large area with TLP to examine the sensitivities related to the total cable length and seabed disturbance for suspended and buried cables, and the cable corridor width and platform weight requirements for an HVAC and HVDC export system. To facilitate this evaluation, we conducted a comparative analysis of two wind farms with different characteristics (Table 5).

Table 5. Characteristics of Two Wind Farms for the Comparative Analysis

Wind Farm Characteristics	Buried Array + HVAC Export Farm	Fully Suspended Array + HVDC Export Farm
Lease Area (km^2)	325	325
Water Depth (m)	1,284	1,284
Mooring Type	TLP	TLP
Turbine Spacing (nmi)	0.65 x 1.00	0.65 x 1.00
Turbine Positions	154	154
Turbine Rating (MW)	15	15
Project Capacity (MW)	2,310	2,310
Array Cable		
Cable Type	132 kV HVAC, three-core	132 kV HVAC, three-core
Cable Diameter (millimeter [mm])	500	500
Buried or Suspended	Buried	Fully suspended 100 m below the water line
Cable Capacity (MW)	142	142
Max. Number of Turbines in Series	9	9
Export Cable		
Cable Type	220 kV HVAC, three-core	± 320 kV HVDC, dual-core
Cable Diameter (mm)	800	2,000
Cable Capacity (MW)	295	1,216
Number of Cables Required in Parallel	9	2
Offshore Substations		
Capacity per Substation (MW)	800	1,200
Number of Substations Required	3	2

The array cable lengths determined in this analysis—buried, suspended, and total—are calculated using the Offshore Renewables Balance-of-System and Installation Tool (ORBIT; Nunemaker et al. 2020), a process-based bottom-up tool for modeling offshore wind balance-of-system installation and costs. To calculate the total disturbed seabed area, we assumed that the seabed disturbance resulting from the burial of a 132-kV cable extended over a width of 20 m.

This assumption, along with the total length of buried cable (in Table 6), provided the basis for estimating the extent of seabed disturbance associated with buried array cables.

As described in Section 2.4, common guidance for cable spacing is between 2 and 3 times the water depth, to allow space for cable repairs. In this scenario assessment, we assumed that pairs of cables could be laid 100 m apart, with adjacent pairs separated by twice the water depth.

Representative substation topside weights for floating HVAC and HVDC platforms were taken from a joint industry design exercise (DNV 2023).

The results associated with the comparative analysis of the wind farms characterized in Table 5 are shown in Table 6.

Table 6. Comparative Analysis Results

Parameters		Buried Array + HVAC Export Farm	Fully Suspended Array + HVDC Export Farm
Total Array Cable Length (km)		629	322
Suspended Length (km)		431	322
Buried Length (km)		198	0
Seabed Disturbance due to Cables (km^2)		3.96	0
Total Export Cable Length (km)		800	200
Export Cable Corridor Width (km)	at 1,284 m	15.8	5.2
	at 1,000 m	12.4	4.1
	at 500 m	6.4	2.1
	at 250 m	3.4	1.1
	at 50 m	1.0	0.3
Weight per Substation (metric tons)		3,000	10,000

The results indicate that buried cables exhibit greater total cable length and seabed disturbance when compared to fully suspended cables, where seabed disturbance is negligible (a suspended cable is not in contact with the seabed, so it does not disturb the seabed). While fully suspended cables do not contribute to seabed disturbance, determining the appropriate depth for their suspension requires consideration of various factors such as cable mechanical properties, layout design, wave protection measures, and navigation concerns. Additionally, the selection of lower-voltage HVAC cables requires more cables and a wider cable corridor than the higher-voltage HVDC cables. In contrast, HVDC converter stations tend to have larger dimensions and greater tonnages than HVAC substations.

4 Construction Methodology

The preparation and construction of a floating wind farm may use various equipment and processes depending on the specific designs of wind farm components and how they interact with the limitations and capabilities of available ports, vessels, and the supply chain. In this section, we outline typical construction processes and some of the possible alternatives under different circumstances. We focus on activities occurring at the wind project site or the staging and integration port. We do not consider activities such as component manufacturing that may occur at other ports or in other regions.

This section covers vessel requirements, staging and integration port facilities, and construction activities for floating wind development in California offshore wind lease areas. We discuss installation of the following major components:

- Moorings and anchors
- Export and array cables
- Floating platforms.

4.1 Vessels

Many different specialized vessel types are involved in the offshore construction and installation of a floating offshore wind farm.

4.1.1 Vessel Types

The number and types of vessels deployed to install a floating offshore wind farm are similar to those used for the construction of a fixed-bottom wind farm. However, there are some significant differences in installation processes that are unique to floating wind farms—for instance, mooring installation and floating platform tow out. An overview of various vessel types deployed during different development phases is shown in Table 7. In general, for each vessel type, there are different vessel sizes that may be more appropriate for installation activities near shore or farther offshore. Other vessels that may be used throughout the construction phase are accommodation vessels—which provide personnel accommodation at the offshore wind plant site—and safety/scout or guard vessels that ensure the safety of marine traffic near the construction area (ACP 2023).

Table 7. Overview of Deployed Vessel Types per Development Phase

Development Phase	Survey Vessel	Heavy-Lift Vessel, Wind Turbine Installation Vessel	Cable-lay Vessel	Anchor-Handling Tug Supply Vessel	Offshore Construction Vessel	Feeder	Crew Transfer Vessel, Service Operation Vessel
Component Staging					X	X	X
Seabed Preparation	X			X	X		
Mooring System Installation	X			X	X	X	X
Turbine Integration		(X)		X			
Platform Tow-Out and Installation				X	X		X
Offshore Substation Installation		(X)		X	X		X
Array Cable Installation	X		X		X		X
Export Cable Installation	X		X	(X)	X		X

(X) means that vessel type is not always used, dependent on the specific project.

Survey vessels are used throughout many different construction phases and equipped with different survey equipment to collect various types of data. In the early phases, survey vessels collect environmental, geotechnical, geophysical, and—if present—unexploded ordnance data. Then, for instance during and after cable installation and dredging activities, the progress is monitored with geophysical surveys. Geotechnical survey vessels collect and test physical seabed samples and geophysical survey vessels can be equipped with different acoustic sensors to map seabed features at wind turbine locations and along the cable routes.

In contrast to their key role in the construction of fixed-bottom offshore wind farms, wind turbine installation vessels and heavy-lift vessels may not be used for floating offshore wind turbine installation. Wind turbines can be integrated with floating platforms in port—using port-based infrastructure such as cranes, self-propelled modular transporters, a drydock, or semisubmersible barges—before being towed the full assembly to the offshore wind site. This approach would not require wind turbine installation vessels or heavy-lift vessels. Alternatively, a wind turbine installation vessel or heavy-lift vessel could be used to integrate the wind turbine and substructure in a protected location. For offshore floating-to-floating assembly in deep waters, vessels equipped with advanced motion compensation would be required, because jack-up operations are not possible in deep water.

Anchor-handling tug supply (AHTS) vessels are built to operate in difficult conditions, equipped with powerful engines and a high bollard pull. AHTS vessels are used to transport, set, install, and recover mooring system components for floating offshore structures. Figure 14 shows an image of the general size and layout of these vessels from a stern view.

Figure 14. Anchor-handling tug supply vessel used for mooring and anchor installation activities.

Offshore construction vessels can be used for a variety of offshore construction activities, such as installing concrete mattresses, performing post-excavation work or transporting materials. Individual offshore construction vessels may be used for different tasks depending on their equipment, such as cranes or ROVs and available deck space.

There are several different types of cable-lay vessels that could be selected for specific operations based on cable turntable size, burial method, or water depths. When laying cables in deep waters, the vessel must be able to maintain its position in the rough seas, and the equipment used to lay the cables must be able to operate at such depths. For (nearshore) shallow-water cable installation, additional vessel types include shallow-water cable installation flat-bottom barges (ACP 2024) and specialized equipment such as a vertical injector—an “L”-shaped, simultaneous lay and burial jetting tool with high-pressure jet nozzles to fluidize soft soils. If dredging operations are required, for instance at cable landfall, there is a variety of different dredger vessels, either hydraulic or mechanical. Fall-pipe vessels can be used to dump rocks or to install scour protection. Alternatively, rocks can also be placed using grab solutions.

For larger equipment and wind plant components, feeder and transport vessels carry construction materials to the construction site, optimizing the utilization of the main vessel so that more time is available for the actual construction work. Feeder vessels, which can be of various types, could be used to supply the main construction and installation vessels on site to optimize logistics and vessel utilization.

Both crew transfer vessels and service operation vessels can be used to transport crew and light equipment during the construction and operation of a wind farm. Crew transfer vessels are more limited in their ability to operate in high sea states and are typically used for projects located less than 2 hours travel—40 nautical miles (75 km)—from port. Service operation vessels are larger vessels that can operate in higher sea states and remain at sea for 1–2 weeks. Especially for floating offshore wind projects, which tend to be further away from the coast with relatively high sea states, service operation vessels might be better suited to ensure safe operations. "Walk to work" vessels have a motion compensated gangway that allows turbine technicians safe access to the wind turbine platform, whereas transfers from a crew transfer vessel to a floating structure may entail additional risks.

4.1.2 Vessel Considerations for California Offshore Wind Leases

4.1.3 Environmental Conditions

The Pacific Ocean has long open distances, with higher, longer waves and longer wave periods compared to other oceans (National Oceanic and Atmospheric Administration 2023). The vessels must be able to operate and carry out offshore installation activities efficiently in these conditions. In addition, due to the water depths of several hundred meters it is not possible to use jack-up vessels. Certain operations such as platform hookup and cable installation will require dynamic positioning and heave compensation to ensure safe and accurate installation of wind plant components.

4.1.4 Jones Act

The Jones Act (46 U.S.C. § 55102) is part of the Merchant Shipping Act of 1920 that applies to goods transported by water within the United States, not only in California. It requires that cargo be carried between two destinations in U.S. water only on vessels that are coastwise qualified: built in the United States, owned and crewed by U.S. citizens, and registered in the United States (U.S. Maritime Administration 2023). Vessels that are coastwise qualified can be used to transport cargo and material between U.S. ports and an offshore wind site. In some cases, coastwise qualified feeder vessels may be used to transport materials from the harbor (Shields et al. 2022).

4.1.5 Ocean-Going Vessel Fuel Regulation

The California Air Resource Board adopted Cal. Code Regs. Tit. 13, § 2299.2 – Fuel Sulfur and Other Operational Requirements for Ocean-Going Vessels within California Waters and 24 Nautical Miles of the California Baseline and Cal. Code Regs. Tit. 17, § 93118.2 – Airborne Toxic Control Measure for Fuel Sulfur and Other Operational Requirements for Ocean-Going Vessels within California Waters and 24 Nautical Miles of the California Baseline. The aim is to reduce sulfur oxide, oxides of nitrogen, and particulate matter emission from vessels to improve the air quality in the state of California (California Air Resources Board 2023; State of California 2011a, 2011b). Compliance with these regulations is another significant consideration for vessels used for offshore wind projects in California.

4.2 Installation Activities

4.2.1 Port Facilities

Construction of offshore wind projects will require port facilities that can support component staging and integration as well as provide berths for installation vessels. Table 8 gives an overview of physical parameters that are relevant for staging and integration port facilities. An additional consideration for fully integrated turbine and platform assemblies is the air draft or clearance above the waterline. Once a wind turbine has been integrated onto a floating platform, it will require an air draft beyond its total height, which may be up to 335 m.

Table 8. Port Infrastructure Parameters

Adapted from Shields et al. (2023)

Port Infrastructure	Approximate Range for Staging and Integration
Acreage (minimum)	30 to 100 acres
Wharf Length (minimum)	1,500 ft
Minimum Draft at Berth	38 ft
Draft at Sinking Basin*	40 to 100 ft
Wharf Loading	>6,000 pounds per square foot (psf)
Uplands/Yard Loading	>2,000 to 3,300 psf

*A sinking basin may be used with a semisubmersible barge to transfer a floating platform into the water; other methods could utilize a ramp or crane.

Outside of staging and integration, ports will be needed to support operations and maintenance, component manufacturing, fabrication, and assembly (Trowbridge et al. 2023; Lim and Trowbridge 2023; Shields et al. 2023).

4.2.2 Mooring and Anchor Installation

After the necessary site surveys and mooring system design processes have been completed, the mooring and anchor installation process for a floating wind farm can begin. Anchors and other mooring system components are loaded onto vessels at port (or transported to the wind farm site via feeder vessels) before the components are installed on-site. Complete mooring systems can be preinstalled prior to the installation of the wind turbine platforms.

Anchor and mooring line installation can be done in one of three primary installation methods: drag embedment, direct embedment, or dynamic embedment. The vessel used depends on the anchor type and installation method. The drag embedment process involves lowering the anchor into the water from the stern of an AHTS (Figure 14), with the mooring line attached, and embedded into the seabed by the thrust of the AHTS and the shape of the anchor. This would apply to drag embedment anchors and vertical load anchors. The direct embedment process typically involves a powerful crane attached to an offshore construction vessel that lifts an anchor from the deck and lowers it into the water and then to the seabed. Additional equipment is used to embed the anchor into the seabed. For example, ROVs can pump water out of the inside of a suction pile to create suction, whereas drilling equipment is lowered to the seabed with drilled piles, which are grouted into place, and then the drilling equipment is brought back to the surface. Other direct embedment anchor types include driven piles, suction-embedded plate anchors, or helical (screw) piles. The dynamic embedment process reduces installation time significantly by allowing the gravitational weight of the anchor to provide the necessary force to embed the anchor into the seabed. Anchors that are dynamically embedded can also be called torpedo anchors. Deadweight anchors can be lowered and set on the seabed by crane with little to no seabed disturbance. Each anchor type will have its own specific installation method, but these are the general approaches.

Mooring lines are typically attached to the anchor during anchor installation and either laid along the seabed or attached to a buoy, ready for connection to a floating offshore wind turbine. These buoys may be set near the seabed to minimize the risk to marine mammals, vessel navigation, and potential damage to the buoy itself.

4.2.3 Array and Export Cable Installation

Installing submarine offshore power cables is a complex endeavor requiring detailed planning and specialized cable installation vessels. Cable installation includes but is not limited to the following steps:

- Route preparation activities
- Cable installation
- Post burial activities.

Design of a cable route takes into account detailed knowledge about the geophysical and geotechnical data, metocean conditions, vessel traffic, and fishing activities. Before laying and burying the cables, the cable routes must be prepared. Route preparation activities may include a pre-lay survey, removal of debris (such as boulders, unexploded ordnance, or out-of-service cables), a pre-lay grapnel run, pre-trenching, and seabed leveling.

The export cable landfall is typically prepared using HDD in advance of the export cable installation. The subsea export cable is connected to onshore grid infrastructure through the HDD pipe, which may be up to 1.5 km (~5,000 feet) long. The California State Lands Commission regulates HDD installation, including burial depth. Considerations for HDD installation include the configuration of the excavation, the potential applicability of a cofferdam, noise levels during installation, and disposal of the dredged material.

Different vessels may be selected for cable installation depending on the site conditions. Cable plows, for example, can bury cables in stiffer soils such as sand or stiff clay. For mud, on the other hand, jetting systems may be more appropriate. Mechanical trenchers can bridge the gap between softer jet-trenchable soils and stiffer soils.

Cables suspended in the water column require buoyancy modules along the cable and tethering to the seabed to protect the cable and keep it in situ. The buoyancy modules are clamped around the cable on the deck of the cable-lay vessel before being installed below the water surface.

The cable segments are connected with offshore joints. The length of the cable segments determines the number of offshore joints required per cable along the cable route. In most cases, no offshore joints are required for an array cable. However, a transition joint will be needed if a cable includes both static and dynamic segments. There are two different types of offshore cable joints, in-line joints and omega joints. In-line joints, as the name implies, are installed in line with the cable route when the cable is laid. For omega joints, the cable segments are preinstalled with an excess length to allow both cable ends to be pulled to the water surface. The cable segments are retrieved from a jointing vessel and joined together on deck. The offshore joint is then lowered into the water and laid on the seabed in the shape of an omega. The advantage of an omega joint is that it decouples the jointing operation from the cable-laying operation; on the other hand, it results in additional cable lengths and disturbance of the seabed, especially in deeper waters.

Crossings of third-party infrastructure (e.g., other power cables, pipelines, or telecommunication cables) are subject to crossing agreements between the parties and typically include protection methods such as concrete mattresses or rock berms to maintain a fixed separation between the cable(s) and/or pipeline. Other crossing solutions are also possible.

The cables can be preinstalled and stored wet, which can be beneficial for the critical path of offshore wind farm installation. Once the floating wind turbines are securely anchored on-site, the field cables can be pulled into each wind turbine, and some can be pulled into the offshore substation or converter station. The same applies to the export cable connecting the offshore substation to the onshore substation (or converter station).

The installation process for array and export cables is similar; however, there are also some important differences between these cable types from the installation point of view:

- Cable length: Export cable length can vary depending on the cable type and design. Typical segment lengths for three-core HVAC export cables are between 20 and 30 km. For HVDC cables, on the other hand, a single cable length can be up to 150 km. Individual cable segments are made as long as possible to avoid offshore joints (ACP 2024). An HVDC circuit includes two cables (+ and -) that can be bundled or separate. The cable lengths are typically limited by the cable manufacturing capacity and the turntable capacity of the cable-lay vessels. For array cables, the segment length is based on the distance between wind turbines.
- Depth of burial: The primary reason for specifying a burial depth is to protect the cable from external damage, such as from a ship's anchor or fishing gear. Depth of burial can be determined by conducting a cable burial risk assessment, which quantifies the risk of external damage to the cable as a function of vessel traffic in the vicinity of the cable route and ground conditions (Ehlers et al. 2023; Carbon Trust 2015; ACP 2024). Because array cables are installed within an offshore wind farm and export cables connect the offshore wind farm to shore over long distances, often crossing shipping lanes, the associated risks are different. Floating offshore wind farms present new challenges in terms of cable risk assessment, as cable segments (or entire array cables) may be suspended in the water column or be laid on the seabed without burial, depending on water depth.
- Cable vessel requirements may also vary, as larger cables require larger turntables, and jointing requires additional deck space (and cable chutes). In addition, different cable-laying tools have different specific handling requirements. For instance, for the landfall cable pull-in, the vessel may be positioned with anchors for better control or be assisted by a jack-up/barge in shallow waters.

4.2.4 Floating Platform Tow-Out and Commissioning

With multiple types of floating platform under consideration, the details of the installation process vary depending on the specific technology. There are also variations in sequencing; for example, array cables may be laid before the platforms are in position or connected afterward. The key element of this installation phase is that the floating platforms are towed from a staging and integration port to their locations at sea where they are connected to their mooring systems. Different vessel types may be used for the towing operation, including AHTS vessels, oceangoing tugs, or a more specialized vessel for a specific platform architecture. Mooring hookup may also require support from an offshore construction vessel, AHTS, or ROV. If wind turbine integration is to be accomplished at the wind farm site using floating-to-floating operations, these would occur after the platforms are moored. Cable hookup can occur at any point after the integrated turbine and platform are securely moored.

Final commissioning is the last stage of the installation process. It involves inspecting and testing key components and subsystems, both mechanical and electrical, before the wind plant begins delivering power to the grid.

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