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Transmission Alternatives for California North Coast Offshore Wind

Volume 4: Cost-Benefit Analysis Report

This report was prepared by Aubryn Cooperman, Patrick Duffy, and Walt Musial of the National Renewable Energy Laboratory (NREL) and published by the Schatz Energy Research Center in March 2022.

Schatz Energy Research Center
Cal Poly Humboldt
Arcata, CA 95521 | (707) 826-4345

Schatz Energy Research Center

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EXECUTIVE SUMMARY

This report analyzes costs associated with the installation of offshore wind power plants with capacities up to 500 megawatts (MW) in the Humboldt Wind Energy Area (WEA), focusing on tradeoffs between the cost of transmission upgrades and possible alternatives such as energy storage. The Northern California coast has an excellent wind resource and could potentially generate gigawatts of electricity from offshore wind. The initial Call for Information and Nominations in the Humboldt area drew responses from 10 developers for up to 2,000 MW of wind energy generating capacity. Although commercial offshore wind power plants on the East Coast will be more than 800 MW, the first project in the Humboldt WEA may be closer to 100 to 200 MW because Northern California lacks the transmission infrastructure that would be required to export electricity from a larger project.

In this report, we model levelized cost of energy (LCOE) for offshore wind plants with capacities up to 480 MW in the Humboldt WEA with a commercial operations date (COD) of 2030. A related report (Daneshpooy and Anilkumar 2022) identified the transmission upgrades that would be required for several plant sizes in this range and estimated the cost of those upgrades. We compare the cost of transmission upgrades with "non-wires" alternatives including curtailment, load growth, and battery energy storage. We consider the levelized cost of transmission (LCOT) to evaluate costs in scenarios with transmission upgrades. For the "non-wires" scenarios, we use the results of production cost modeling to estimate revenues.

This report focuses on modeling scenarios with characteristics that will likely be relevant to an initial offshore wind project in the Humboldt WEA. Plant capacities are less than 500 MW, the modeled COD is 2030, and the representative technology is a 12-MW turbine on a floating semisubmersible substructure. Costs for turbine procurement, operations and maintenance, and financing come from the Offshore Regional Cost Analyzer (ORCA), whereas we use NREL's Offshore Renewables Balance-of-System and Installation Tool (ORBIT) to model procurement costs for the remainder of the offshore wind equipment as well as installation costs.

Scenarios with Full Deliverability require transmission upgrades to enable the delivery of the full output of the offshore wind plant during peak demand periods. One of the "non-wires" alternatives considered in several scenarios is Energy Only deliverability status, which avoids the cost of transmission upgrades but may incur additional curtailment. The level of curtailment and revenue from generation in Energy Only scenarios was estimated by Daneshpooy and Anilkumar (2022) using a production cost model. Additional scenarios consider the impacts of a 4-hour, 15 MW battery energy storage system (BESS) on total system cost, curtailment, and revenue.

Results

A comparison of capital costs vs. plant capacity for offshore wind plants in the Humboldt WEA with a COD of 2030 are presented in Figure ES.1. Although the relationship between total capital expenditures (CapEx) and plant capacity appears linear, examination of the CapEx per kilowatt shows a steep decrease between 24 and 144 MW, with a slower decline in costs for larger plant sizes. Trends in LCOE are similar, starting above $95 per MWh and decreasing to $74 per MWh for a plant capacity of 480 MW.

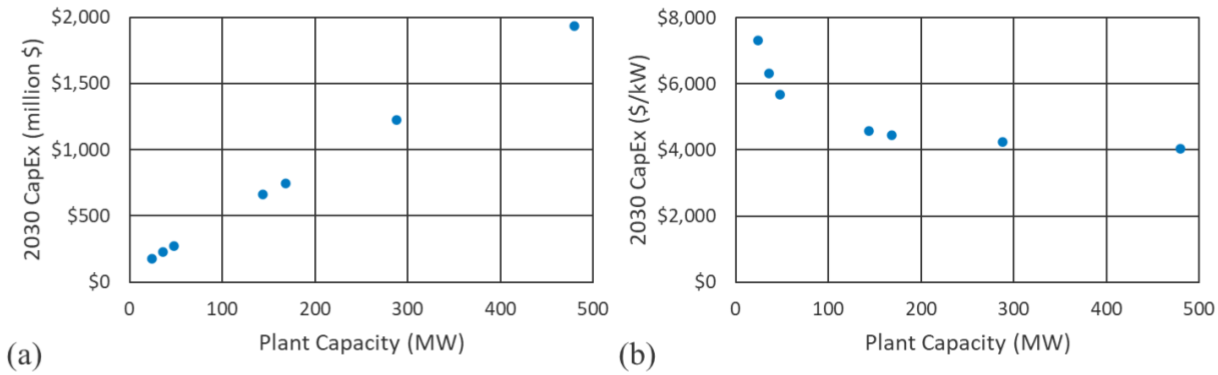

Figure ES.1. Capital expenditures (CapEx) for offshore wind plants in the Humboldt WEA with a 2030 COD for plant capacities between 24 and 480 MW. (a) total CapEx and (b) CapEx per kilowatt.

We analyze costs for two sets of scenarios: one set includes costs for transmission upgrades while the other set includes costs for alternatives to building new transmission. The first set of scenarios model the cost of offshore wind plants with Full Deliverability status. Transmission upgrades would be required to enable Full Deliverability for all plant capacities larger than 30 MW, and the cost of these upgrades was estimated in Task 2.2 (Daneshpooy and Anilkumar 2022). Table ES.1 summarizes the cost of energy and transmission upgrades for offshore wind (OSW) plant capacities up to 480 MW. Transmission upgrade costs for a plant capacity of 48 MW were evaluated in a previous study (Pacific Gas and Electric Company 2020) using a different methodology and are not reassessed here. For the plant sizes considered, LCOE decreases as the capacity increases, but the cost of transmission upgrades reduces or eliminates the advantage of larger plant capacities.

Table ES.1. Levelized cost of energy and transmission for Full Deliverability scenarios.

OSW Plant Capacity	*48 MW*	*144 MW*	*288 MW*	*480 MW*
OSW CapEx (million $)	$273	$661	$1,225	$1,935
Transmission CapEx (million $)	—	$168 to $238	$329	$591 to $1,123
OSW OpEx (million $ per yr)	$3.4	$10.0	$20.0	$33.3
Net AEP* (GWh)	219	660	1,317	2,160
LCOE ($ per MWh)	$96	$80	$75	$73
LCOT ($ per MWh)	—	$12 to $17	$12	$13 to $25
LCOE + LCOT ($ per MWh)	—	$92 to $97	$87	$86 to $98

*AEP = annual energy production

The Energy Only scenarios summarized in Table ES.2 do not include transmission upgrades, but they have higher LCOEs than the equivalently sized Full Deliverability counterparts because their energy output is reduced by curtailment. However, the LCOE of the 144-MW Energy Only scenario is lower than the LCOE + LCOT of the 144-MW Full Deliverability scenario, and the 168-MW Energy Only scenarios have marginally lower LCOEs than the corresponding 144-MW scenarios. At 288 MW, the level of curtailment is much higher, as is the LCOE. Larger plant capacities face greater curtailment because local electricity demand is met and the ability to deliver energy to the rest of the California grid is constrained. This local saturation depresses the locational marginal prices (LMPs), reducing revenues for larger plant capacities. We use the difference between wind farm revenues and cost (revenues per MWh – LCOE) as a proxy for profit. All plant capacities have a negative difference, indicating that revenues do not exceed the cost of the wind farm.

Table ES.2. Levelized cost of energy and revenue for Energy Only deliverability scenarios.

Scenario	*144 MW baseline load*	*144 MW + 15 MW, 4 hr storage*	*168 MW baseline load*	*168 MW augmented load*	*168 MW baseline load + storage*	*288 MW baseline load*
OSW + storage CapEx (million $)	$661	$672	$748	$748	$760	$1,225
OSW + storage OpEx (million $ per yr)	$10	$11	$12	$12	$12	$20
Curtailment (%)	4.4%	4.5%	6.0%	5.8%	5.5%	36.5%
Net AEP (GWh)	632	628	724	726	725	836
LCOE ($ per MWh)	$84	$86	$83	$83	$85	$119
Average LMP ($ per MWh)	$33	$36	$16	$22	$22	-$14
Revenue ($ per MWh)	$58	$63	$41	$47	$50	$11
Δ [Revenue – LCOE] ($ per MWh)	-$26	-$24	-$42	-$36	-$35	-$108

Energy Only scenarios that include the addition of energy storage in the form of a 4-hour, 15 MW BESS or augmented (increased) load perform better in terms of revenues and Δ [revenues – costs] than their baseline load counterparts. This is due to the ability to sell energy at higher prices during times of day when demand is high and indicates that the BESS adds more value than it costs for the plant capacities considered. This study only considered a single capacity and storage duration for the BESS. Additional analysis would be required to identify an optimal BESS size that could produce more revenue.

With the available information, the key dynamics illustrated by the above scenarios appear to be:

- Lower power plant costs per MWh (LCOE) for larger offshore wind plant capacities
- Higher transmission costs per MWh (LCOT) for the smallest and largest plants
- Suppression of revenue for Energy Only plants as capacity increases, caused by transmission constraints and local energy market saturation
- Lower LCOEs for the 144-MW and 168-MW Energy Only scenarios than the combined LCOE + LCOT of the 144-MW Full Deliverability scenario
- Increased revenue in Energy Only scenarios with BESS or Augmented Load.

It is important to note that even though the floating offshore wind cost results for the year 2030 were obtained using a conservative deployment assumption (4.9 GW) for the learning curve, the underlying learning rate was derived based on commercial-scale fixed-bottom industry cost data. This means that the cost reductions may be overstated because the commercial-scale fixed-bottom projects benefit from more mature supply chains than would a pilot-scale floating project in Humboldt.

Among all of the scenarios considered, the 288-MW plant offered the lowest cost for Full Deliverability, while the 144-MW plant offered the most favorable difference between revenue and LCOE. The addition of energy storage enabled revenue gains for the 144-MW and 168-MW plants that outweighed the cost of the BESS. Other potential revenue streams, such as Resource Adequacy, were not included in this analysis. Although not assessed in detail here, offshore wind development can present opportunities for economic development that scale with the project size and resulting in both costs and benefits for stakeholders in the Humboldt region.

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1. INTRODUCTION

The purpose of this report is to compare the costs and benefits of installing offshore wind power plants with capacities up to 500 megawatts (MW) in the Humboldt Wind Energy Area (WEA), with a focus on identifying the costs related to transmission upgrades and possible alternatives such as energy storage. This study builds on previous work that examined the feasibility of offshore wind development on California's North Coast (Severy et al. 2020a). That work included an interconnection feasibility analysis conducted by the Pacific Gas and Electric Company (PG&E) (2020) in collaboration with the Schatz Energy Research Center, which looked at the feasibility of interconnecting offshore wind power plants with capacities of 48 MW, 144 MW, and 1,836 MW in the Bureau of Ocean Energy Management's (BOEM's) Humboldt WEA to the transmission system in the region of Humboldt Bay. Cost estimates for the transmission system upgrades recommended in PG&E's study (Table 1) were high relative to the capital costs to install the offshore wind plant, especially for the smaller plant capacities. In this report, we model costs for offshore wind power plants on the lower end of the range of capacities considered by PG&E and examine alternatives to transmission upgrades that may reduce total system costs or offer higher revenues.

Table 1. Cost estimates for interconnection of offshore wind power plants in the Humboldt Wind Energy Area from (Pacific Gas and Electric Company 2020)[*].

Nameplate Capacity	*Low Interconnection Cost Estimate*	*High Interconnection Cost Estimate*
48 MW	$365 million ($7,600 per kW)	$730 million ($15,200 per kW)
144 MW	$669 million ($4,650 per kW)	$1,340 million ($9,310 per kW)
1,836 MW	$1,400 million ($763 per kW)	$5,800 million ($3,160 per kW)

This study also provides detailed cost estimates for offshore wind power plants with capacities below 500 MW in the Humboldt WEA. Previous work was based on an assumed plant capacity of 1 GW (Beiter et al. 2020).

This cost-benefit analysis report is part of a collaborative effort to assess the impact that transmission alternatives can have on the economic viability of modest scale (less than 500 MW) offshore wind development in the Humboldt WEA. Supported by funding from BOEM, this collaboration is being led by the Schatz Energy Research Center at Cal Ploy Humboldt. Partners include the National Renewable Energy Laboratory and Quanta Technology, LLC. The research is comprised of four tasks, each of which features a standalone report. Descriptions of the four tasks and the responsible parties are shown in Table 2.

Table 2. List of Tasks for California North Coast Offshore Wind Transmission Alternatives Study

Task Description	*Responsible Party*
Task 1. Wind Resource Assessment	Schatz Energy Research Center
Task 2.1 Description of Transmission Alternatives	Schatz Energy Research Center
Task 2.2 Transmission Analysis	Quanta Technology, LLC
Task 2.3 Cost-Benefit Analysis	National Renewable Energy Laboratory

[*] The methodology used by PG&E to determine required transmission upgrades and estimate associated upgrade costs differed from the approach that Quanta Technologies used in conducting this current research. PG&E's study was a feasibility study, which used the most conservative study assumptions to provide an indicative estimate of worst-case upgrades, and it did not distinguish which costs would be borne by the project developer. This resulted in higher costs estimates in the PG&E 2020 study.

2. METHODS

We use levelized cost of energy (LCOE) and levelized cost of transmission (LCOT) to evaluate the costs of the different transmission alternative scenarios considered in this report. See sections 2.5 and 2.6 for detailed definitions of LCOE and LCOT, respectively. This section outlines the key assumptions and methods for developing the scenarios and calculating LCOE. First, we provide an overview of the core assumptions informing the study, then outline the transmission alternative scenarios considered, before describing the methodology for calculating LCOE and LCOT and projecting future costs.

2.1 Technology Assumptions

This study focuses on early-stage offshore wind development along California's North Coast, so we assess cost tradeoffs using near-term offshore wind energy technologies (likely to be deployed in the next 5 to 10 years).

The water depths in the Humboldt Wind Energy Area are between 550 m and 1100 m, making it too deep for fixed-bottom foundations which currently have a maximum economic water depth close to 60 m. Floating foundation technology is therefore required to facilitate offshore wind energy in California, and it is rapidly advancing towards the commercial stage (Musial et al. 2021b). Figure 1 shows the three main floating substructure topologies being developed, including the spar-buoy, the semisubmersible, and the tension leg platform.

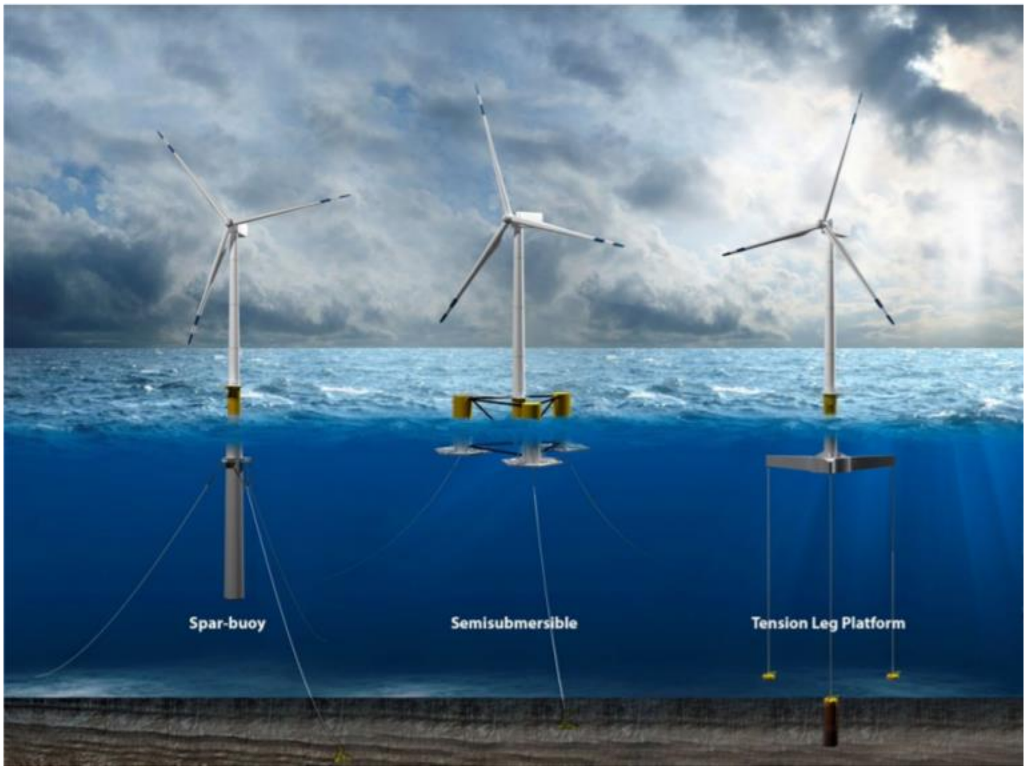

Figure 1. Floating offshore wind substructure topologies including spar-buoy, semisubmersible, and tension leg platform. Illustration by Josh Bauer, NREL.

As of 2021, the largest operational floating offshore wind farm in the world is Kincardine in Scotland, with a plant capacity of 50 MW (Durakovic 2021b). The project deployed one 2.0-MW and five 9.5-MW wind turbines on semisubmersible platforms in water depths of up to 80 m. More than 75% of floating wind energy projects that have announced substructure technology choices intend to use semisubmersible substructure technology (Musial et al. 2021b). For this study, we assume that semisubmersible substructure technology will be deployed offshore California, consistent with Beiter et al. (2020).

One important consideration regarding floating substructure technology types is the anchor footprint—the area required for the mooring lines and anchors. The anchor footprint depends on the mooring line design, the substructure type, the water depth, and the seabed conditions, and it sets the minimum distance between individual turbines and the boundaries of BOEM Lease Areas. We have assumed a required minimum distance of 2.5 times the water depth, which falls within the range of likely values for a semisubmersible platform with a catenary mooring system.

The wind turbine has the largest impact on cost through its energy production, as well as its contribution to capital expenditures (CapEx). Capacity factors have increased significantly as the wind industry has matured and capacity factors for offshore wind globally average 8% higher than onshore (Beiter et al. 2021). Offshore wind energy costs have fallen substantially in recent years, and this trend is expected to continue (Wiser et al. 2021). Turbine upsizing plays a significant role in cost reductions by enabling lower balance of system costs and operational expenditures (OpEx) for a given plant capacity, thereby incentivizing developers to opt for the largest turbine available at the time of construction (Shields et al. 2021a).

This study assumes a turbine rating of 12 MW to be representative of near-term projects. This may be a conservative assumption based on recent announcements. The largest operating offshore wind turbine in the world is the GE Haliade-X prototype, which has been upgraded to produce a maximum 14 MW of power after initially beginning operation with a rating of 12 MW (General Electric 2021). Vineyard Wind 1, the first commercial scale U.S. offshore wind project, intends to install 13 MW Haliade-X turbines for commercial operation by 2023 (Kellner 2021). Larger turbines are on the horizon. Siemens Gamesa shipped the nacelle of its SG 14-222 DD (14 MW) prototype for assembly at the Østerild test site in Denmark (Durakovic 2021a). Vestas announced they would also build its V236-15.0 MW prototype at Østerild (Vestas 2021). MingYang Smart Energy announced it will develop a 16 MW offshore wind turbine with a target of commercial production in 2024 (MingYang Smart Energy 2021). The turbine parameters for the 12 MW offshore wind turbine used in this analysis are presented in Table 3.

Table 3. Summary of Offshore Wind Turbine Technology Parameters

Parameter	*Value*
Turbine rated capacity (MW)	12
Rotor diameter [D] (m)	222
Hub height (m)	138
Substructure technology	Semisubmersible
Mooring technology	Drag embedment anchors

2.2 Offshore Wind Plant and Site Characteristics

We consider plant capacities between 24 MW (two turbines) and 480 MW (40 turbines). The plant layouts are the same as those modeled in Task 1 (Younes et al. 2022): a rectangular offset grid with 7 turbine rotor diameter (7D) spacing east to west, 8.7D spacing north to south, and a 50% offset between rows. To determine the size of the lease area required for each plant, we assume that the mooring footprint on the seabed extends beyond the outermost turbines in the rectangle by a factor of 2.5 times the water depth.

Turbines are connected within the wind plant via 66 kV array cables that are suspended in the water column at a depth of 300 m below the surface. For plant capacities less than 200 MW, power is aggregated and transmitted back to shore using one or two (depending on plant capacity) 66 kV export cables, the same voltage as the array cables. Larger plants (with capacities greater than 200 MW) include a substation to collect power from the array system and transform it to 132 kV for transmission to shore.

The export system comprises one or more submarine cables between the substation and cable landfall, then 2 km of onshore transmission line to reach the point of interconnection at Humboldt Bay substation.

Physical site characteristics impact the design and cost of an offshore wind plant. We used the physical properties at the centroid of the Humboldt WEA as our baseline inputs for cost modeling (Table 4).

Table 4. Site and plant characteristics, baseline values for Humboldt WEA centroid

Description	*Value*
Mean wind speed at 100 m	10.8 m per s
Water depth	686 m
Distance to port	45 km
Distance to cable landfall	45 km
Array cable depth	300 m
Onshore cable (spur line) length	2 km

In addition to the baseline case, we also investigated the sensitivity of our LCOE estimates to plant location by considering additional offshore wind plants with physical properties matching the East and West centroid locations studied in Task 1 (Figure 2).

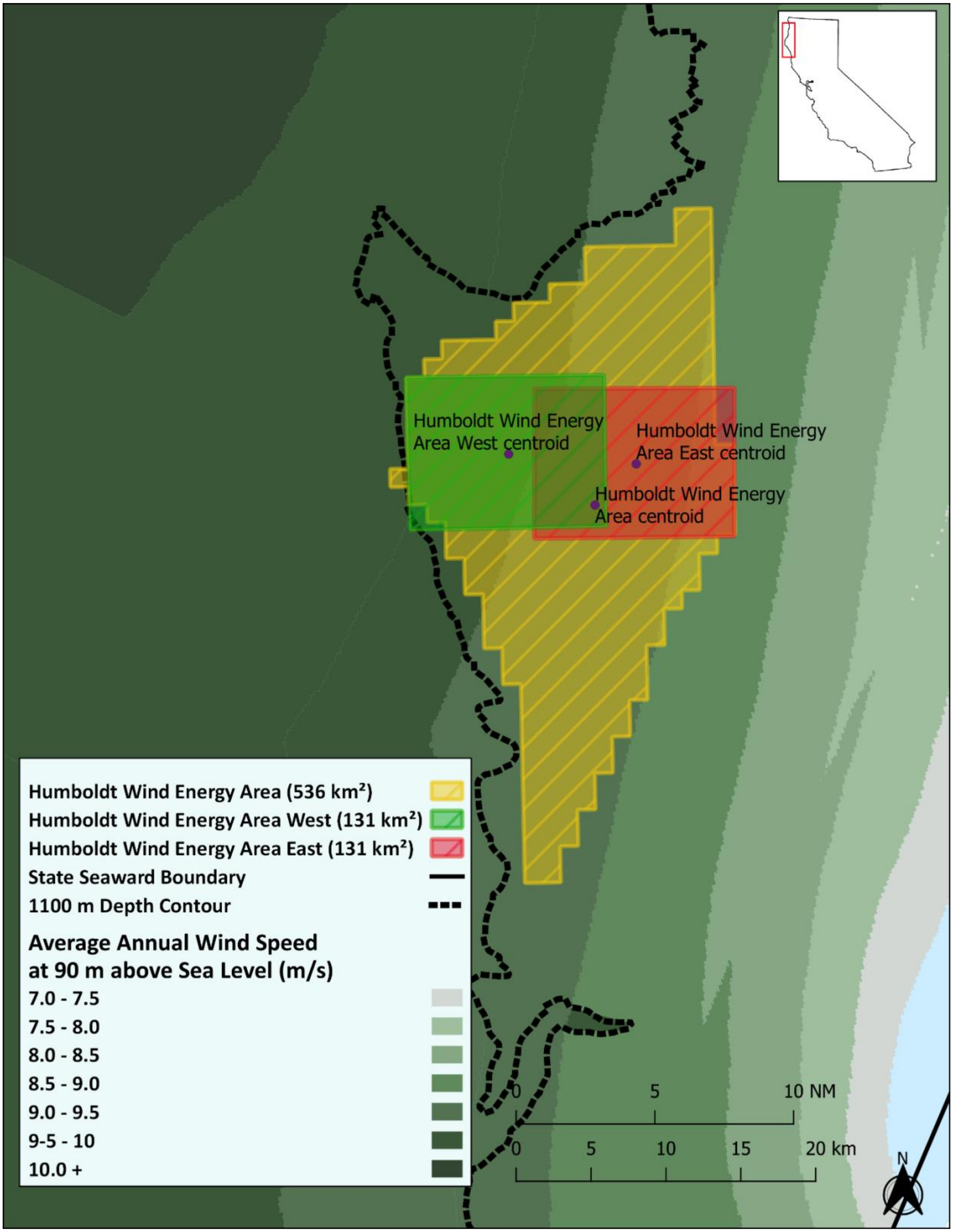

Figure 2. Centroids of the hypothetical wind farms in the Humboldt WEA are depicted as purple dots.

2.3 Financing Assumptions

We utilize the financing assumptions outlined in NREL's Annual Technology Baseline R&D Financing Scenario to inform the techno-economic modeling of offshore wind costs in the Humboldt Wind Energy Area (NREL 2021). These financing terms are informed by Feldman et al. (2020). Floating offshore wind projects are assumed to benefit from similar financing terms as the commercial-scale fixed-bottom offshore wind market due to assumed similarities in project developer experience, mature supply chains, low political risk, technology maturity, limited-to-no revenue risk, insurance coverage, contract management practices, and contingency budgets (Weber 2020). A summary of the financial assumptions is provided in Table 5. The baseline financing assumptions do not include tax credits. Note that some of these assumptions may be non-conservative due to the nascent state of the floating industry.

Table 5. Summary of Financing Assumptions

Financing Parameters	*Nominal*	*Real*
Project design life	30 years	30 years
Combined state and federal tax rate	26%	26%
Inflation rate	2.5%	2.5%
Weighted average cost of capital (after-tax)	5.2%	2.6%
Capital recovery factor (after-tax)	6.6%	4.9%
Depreciable basis	100%	100%
Depreciation schedule	5-year MACRS	5-year MACRS
Depreciation adjustment (NPV)	87%	87%
Project finance factor	104%	104%
Fixed charge rate	6.9%	5.1%

2.4 Transmission Upgrades and Non-Wires Alternatives

The Task 2.2 report by Quanta Technology (Daneshpooy and Anilkumar 2022) identifies transmission upgrades that would be required to provide Full Deliverability for 144-MW, 168-MW, 288-MW, and 480-MW offshore wind plants and estimates the associated costs. Several alternatives to transmission upgrades, described here as "non-wires" alternatives, are also considered in this study. The non-wires alternatives are:

- **Augmented load**: The augmented load case assumes a greater degree of electric load growth—for example through electrification of vehicles and building heating—than the baseline demand profile.
- **Energy-only deliverability status**: Generators that opt to participate in the CAISO market as "Energy Only" are not eligible to receive Resource Adequacy payments, but their interconnection costs can be lower because they are only required to pay for reliability network upgrades and not local or area deliverability network upgrades.
- **Battery energy storage system (BESS)**: These cases include a 4-hour, 15-MW BESS that stores energy from the offshore wind power plant during periods of high generation and low demand and releases the energy when there is less wind energy and/or more electricity demand. The BESS participates in the market for ancillary services (e.g., regulation) in addition to the energy market.

2.5 Levelized Cost of Energy

We use several modeling tools to compute components of LCOE based on the definition from Short et al. (1995) as shown in Equation 1:

$$LCOE = \frac{(CapEx \times FCR) + OpEx}{(AEP_{Net} \div P)}$$

Equation 1

where:

LCOE = levelized cost of energy ($ per MWh)
FCR = fixed charge rate (% per year)
CapEx = capital expenditures ($ per kW)
AEP_{net} = net average annual energy production (MWh per year)
OpEx = average annual operational expenditures ($ per kW-year)
P = total wind plant capacity (kW).

Note that CapEx may be represented as the sum of turbine, balance-of-system (BOS), and soft costs as shown in Equation 2.

$$CapEx = C_{Turbine} + C_{BOS} + C_{Soft}$$

Equation 2

where:

$C_{Turbine}$ = turbine capital expenditures
C_{BOS} = balance-of-system capital expenditures
C_{Soft} = soft costs.

Turbine capital expenditures include the cost to procure the turbines and towers from original equipment manufacturers. BOS costs include all expenses required to construct a wind energy project except the acquisition of the turbines and towers. These costs include the procurement costs for all other components (such as substructures, cables, and electrical infrastructure), offshore and land-based construction costs, port costs, site surveying fees, permitting fees, and leasing fees (BVG Associates 2019). Soft costs represent construction financing costs, construction insurance, and cost contingencies. The core components of LCOE are listed in Table 6 along with the method or tool used to compute them and the relevant sources.

Table 6. Summary of LCOE components and modeling methodology.

LCOE Component	*Method*	*Sources*
FCR	Obtained from literature	(Feldman et al. 2020; NREL 2021; Stehly et al. 2020)
$C_{Turbine}$	Obtained from literature	(Musial et al. 2021b)
C_{BOS}	BOS computed with ORBIT	(Nunemaker et al. 2020)
C_{Soft}	Soft costs based on ORCA	(Beiter et al. 2016)
OpEx	OpEx based on ORCA and adjusted for plant size	(Beiter et al. 2016; Shields et al. 2021a)
AEP_{net}	Computed in Task 1	(Younes et al. 2022)

2.5.1 Capital expenditures

We assume a turbine CapEx of $1,300 per kW based on analysis of industry data (Musial et al. 2021b). This is consistent with recent NREL offshore wind cost analyses (Beiter et al. 2020; Musial et al. 2021a; Shields et al. 2021b; Stehly et al. 2020).

NREL's Offshore Renewables Balance-of-System and Installation Tool (ORBIT) is used to compute balance-of-system components of CapEx (Nunemaker et al. 2020). ORBIT is NREL's Python-based, open source[†], bottom-up offshore wind BOS cost model, which simulates the design and installation phases of offshore wind projects to estimate costs.

Soft costs are calculated using the framework from NREL's Offshore Regional Cost Analyzer (ORCA) to account for costs associated with insurance, project financing, contingencies, and project management (Beiter et al. 2016).

2.5.2 Operational expenditures

The annual OpEx is derived from ORCA and comprises two parts: a flat operational cost per kilowatt and a maintenance cost that varies depending on the distance from port and the severity of the wave climate. Because ORCA assumes a standard plant capacity of 600 MW, we adjust the maintenance cost for smaller plant capacities using the relationship derived in Shields et al. (2021a) for OpEx as a function of plant size. Smaller facilities have higher maintenance costs on a per kilowatt basis because they are unable to benefit from some of the economies of scale that larger facilities can leverage.

2.5.3 Annual energy production

Annual energy production (AEP) is the only variable in the denominator of the LCOE equation and therefore has a strong influence on the cost. For the purposes of the current study, we rely on previous work conducted at the Schatz Energy Research Center analyzing the AEP of different wind plants in the Humboldt Wind Energy Area (Severy et al. 2020b; Younes et al. 2022). The results from the most recent analysis are summarized in Table 7. A plant capacity of 168 MW was not simulated in Task 1; we assumed that the capacity factor would be approximately equal to that of the 144-MW plant, resulting in an AEP of 760 GWh.

[†]Code and documentation are available on GitHub, and the model methodology is described in "ORBIT: Offshore Renewables Balance-of-System and Installation Tool" (Nunemaker et al. 2020).

Table 7. Annual energy production summary for Humboldt WEA wind farm scenarios (Younes et al. 2022)

Location	*Size (MW)*	*95% Confidence Interval for Population Mean (GWh per yr)*	*95% Tolerance Interval (GWh per yr)*
East	48	217 +/- 5.47	185 to 250
Centroid	48	219 +/- 5.47	187 to 251
West	48	222 +/- 5.3	191 to 253
East	144	647 +/- 16.3	552 to 743
Centroid	144	652 +/- 16.3	556 to 747
West	144	662 +/- 15.8	569 to 754
East	288	1,290 +/- 32.5	1,100 to 1,480
Centroid	288	1,300 +/- 32.5	1,110 to 1,490
West	288	1,320 +/- 31.5	1,130 to 1,500
East	480	2,150 +/- 54	1,830 to 2,460
Centroid	480	2,160 +/- 54	1,840 to 2,480
West	480	2,190 +/- 52.3	1,890 to 2,500

2.6 Levelized Cost of Transmission

The levelized cost of transmission (LCOT) expresses the cost of upgrades to the transmission system in a way that is comparable with the LCOE, while maintaining separation between these two types of costs. Transmission upgrades may be paid for by entities other than offshore wind developers, and the lifetime of the transmission upgrades may be different than that of the wind plant. Gorman et al. (2019) represent LCOT in the following way:

$$LCOT = \frac{C * r}{AEP_{net} * [1 - (1 + r)^{-n}]} \qquad \text{Equation } 3$$

where:

C = capital cost of transmission investment
r = discount rate (assumed to be 4.4%)
AEP_{net} = net average annual energy production (MWh per year)
n = transmission asset lifetime (assumed to be 60 years).

The LCOT includes the cost of upgrades to the onshore transmission system that were identified as part of Task 2.2 (Daneshpooy and Anilkumar 2022). Note that the wind farm export cable and a 2-km onshore spur line are included in LCOE for the OSW plant and do not contribute to LCOT for this analysis.

2.7 Projecting Future Costs

This study employs the learning-curve based cost projection methodology developed in Beiter et al. (2020) to estimate 2030 floating offshore wind cost. Future costs are obtained by applying the learning curve cost reductions to the baseline costs obtained with ORBIT. Cost reductions associated with turbine and plant scaling are captured in ORBIT (Shields et al. 2021a).

Learning and experience curves represent the decrease in input costs as an increasing number of units of a good or service are produced (Louwen et al. 2019). An offshore wind industry learning rate describes the percentage cost reduction for each doubling of cumulative installed offshore wind capacity. Louwen et al. (2019) attribute these cost reductions to:

- Learning by doing
- Learning by researching
- Improved supply chain and manufacturing efficiencies
- Investment

We obtain the learning rate of 11.9% per doubling of installed capacity from the same experience factor (-0.182) derived by Beiter et al. (2020)[‡] from a multivariate linear regression of publicly available historical offshore wind CapEx data going back to 2014. Since limited cost data are available for the few existing pilot-scale floating offshore wind projects, commercial scale fixed-bottom cost data were analyzed to obtain the experience factor. The linear regression process controls for turbine rating, plant capacity, water depth, distance to shore, and installation country to remove their effects from the linear regression so that the result can be applied to all projects equally. Because empirical data for OpEx are unavailable to derive a learning curve, the learning rate is assumed to be the same as that of CapEx.

This learning rate is then translated into a learning curve (and cost reductions) based on projected global floating offshore wind deployment in 2030 (commercial operation date). We assume the level of floating deployment in 2030 to be 4.9 GW based on the Conservative Scenario from the 2021 Annual Technology Baseline (NREL 2021), which is based on an average of floating deployment projections from literature. We chose the 4.9-GW Conservative Scenario because the fixed-bottom project data underlying the learning curve are from commercial scale projects. This study focuses on pilot-scale projects, meaning that using the Moderate ATB scenario deployment would likely overstate supply chain maturity and therefore cost reductions.

3. RESULTS

3.1 Offshore Wind Farm Costs

Capital expenditures include the wind turbines, floating substructures, subsea cables, and other balance-of-system equipment, as well as installation of all wind farm components. Figure 3 provides estimates of total CapEx and CapEx per kilowatt for offshore wind plant capacities between 24 MW and 480 MW with a 2030 COD. Although larger wind power plants have higher total CapEx, the CapEx per kilowatt decreases with increasing plant size as the costs of vessel mobilization and balance-of-system components are amortized across a greater number of turbines. The steepest decrease in costs occurs between plant capacities of 24 to 48 MW, so the remainder of the analysis focuses on plant sizes of 48 MW and larger.

[‡] See Appendix A. in Beiter et al. (2020) for a more detailed discussion of the derivation of the experience factor and learning rate.

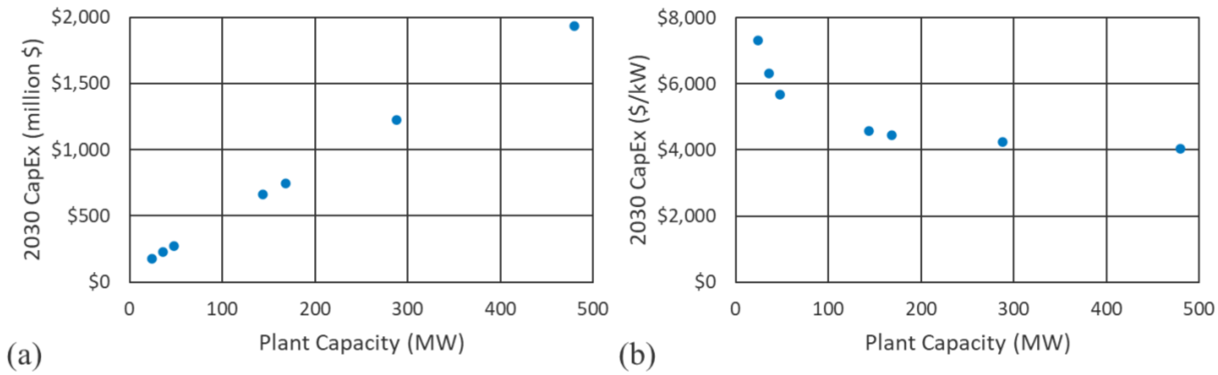

Figure 3. Wind farm CapEx in 2030 in terms of (a) total $ and (b) $ per kW

We used physical site characteristics such as water depth and distance to port measured at the centroid of the Humboldt WEA to model costs for each plant capacity shown in Figure 3. Because these parameters vary across the WEA, wind turbines installed at any given site could experience higher or lower costs than the baseline case. To examine the sensitivity of the total CapEx to key site characteristics, we varied five physical parameters by ±20% with respect to the baseline values. Figure 4 shows the percentage change in the total CapEx for a 144-MW plant capacity that results from increasing and decreasing these parameters. Three of the parameters selected vary by more than 20% for sites within the Humboldt WEA, and the effect of this additional range is also shown in Figure 4.

Water depth has the largest effect on CapEx, potentially increasing costs by 4.5% as the depth goes from 686 m to 1100 m. The biggest contributor to the change in CapEx with water depth is the increased cost of the mooring system, which requires longer mooring lines that take more time to install in deeper waters. The distance to port has a relatively small impact on costs for the range of distances considered here, although in practice any increase in the distance to port would likely coincide with increasing the distance to cable landfall because the port and point of interconnection are very close together in this study. The range of onshore cable lengths accounts for two possible routes crossing the north or south spit of Humboldt Bay, as described in Porter and Phillips (2020a).

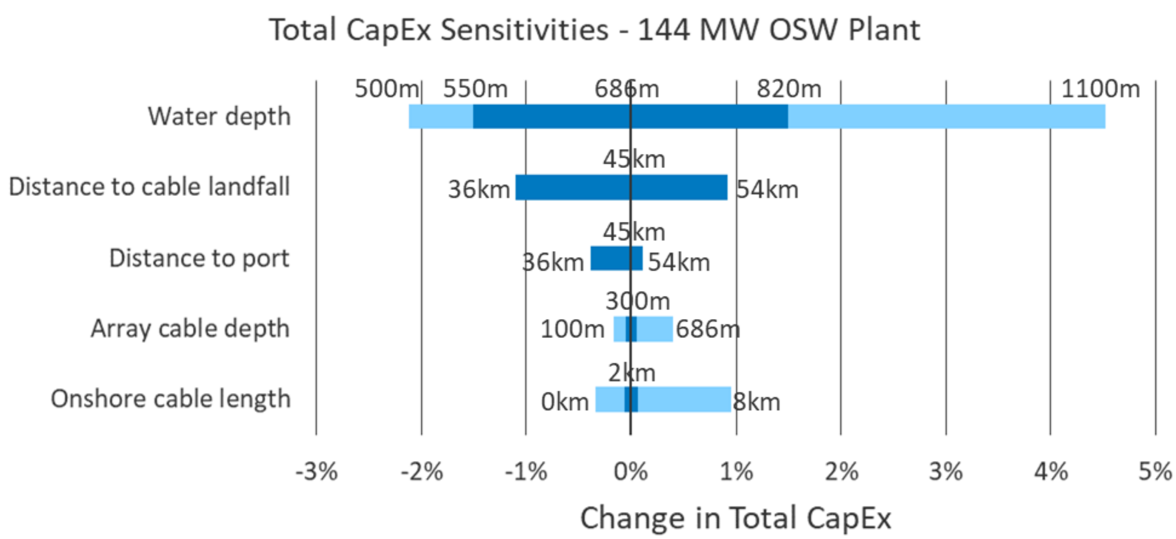

Figure 4. Change in total capital expenditures relative to the baseline value for a 144-MW offshore wind power plant when varying physical site parameters by ±20% (dark bars) or across the range of possible values within the Humboldt WEA (light bars). Labels by each bar indicate the value of the parameter corresponding to the baseline (center), low, and high CapEx results.

The impact of site selection on costs is more complex than we can model by varying individual physical parameters. Between any two locations within the Humboldt WEA, there are differences in multiple characteristics that affect capital costs such as water depth and distance to shore, and there are also variations in the wind resource that affect the overall cost of energy. To explore some of the possible effects of combining these parameters, we compared cost projections for a 144-MW wind farm using physical characteristics from the centroids of the East, Center, and West study areas from Task 1 (Table 8). The West study area is deeper and farther from shore than the Center study area, but it also has a stronger wind resource that enables greater energy production, while the opposite is true of the East study area. Overall, the difference in LCOE is less than 0.3% across the three locations.

Table 8. Comparison of costs for a 144-MW wind farm with 2030 COD at 3 study locations

Parameter	*Units*	*East*	*Center*	*West*
Water depth	m	672	686	750
Distance to port and cable landfall	km	42	45	50
Mean wind speed	m per s	10.7	10.8	11.1
CapEx	$ per kW	$4,530	$4,579	$4,664
OpEx	$ per kW-yr	$70	$70	$70
Capacity Factor	%	54.2%	54.7%	55.5%
FCR (nominal)	%	6.9%	6.9%	6.9%
LCOE	**$ per MWh**	**$80.84**	**$80.89**	**$81.06**

Figure 5 presents the LCOE based on 2030 COD for plant capacities between 48 MW and 480 MW at each of the three study locations. The LCOE is above $95 per MWh for the 48-MW plant and decreases to $74 per MWh at a plant capacity of 480 MW. Variation in LCOE between the three study locations is largest at the 48 MW plant size and the three values tend to converge as plant capacities increase.

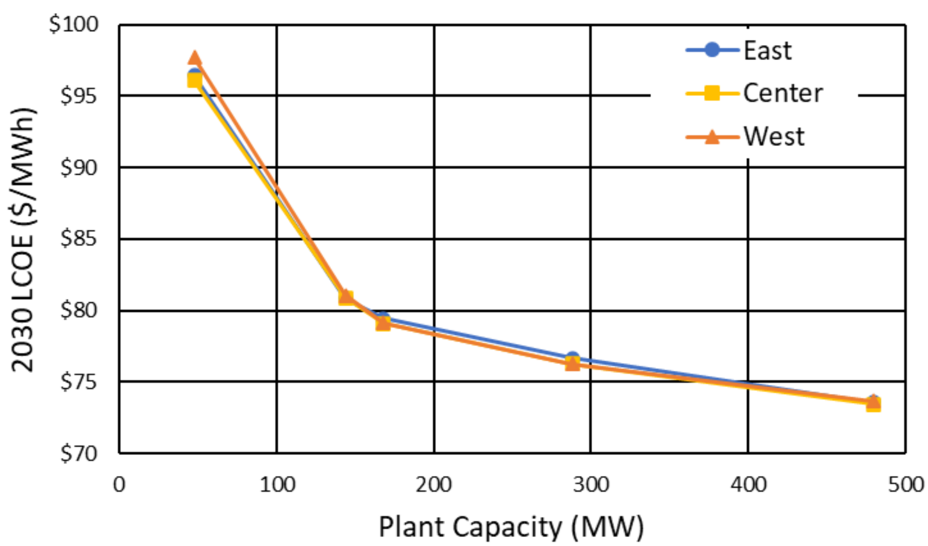

Figure 5. LCOE for OSW plant capacities between 48 MW and 480 MW with a 2030 COD

Figure 6 examines the sensitivity of the LCOE to each of the main financial inputs. To illustrate the relative sensitivity of LCOE, each input is varied by 20% from the baseline value, although this does not necessarily reflect the most likely range in each parameter. Variation in the capacity factor produces the largest change in LCOE, while variations in OpEx have the smallest effect. Increasing the nominal weighted average cost of capital (WACC) by one percentage point increases the LCOE by 11%.

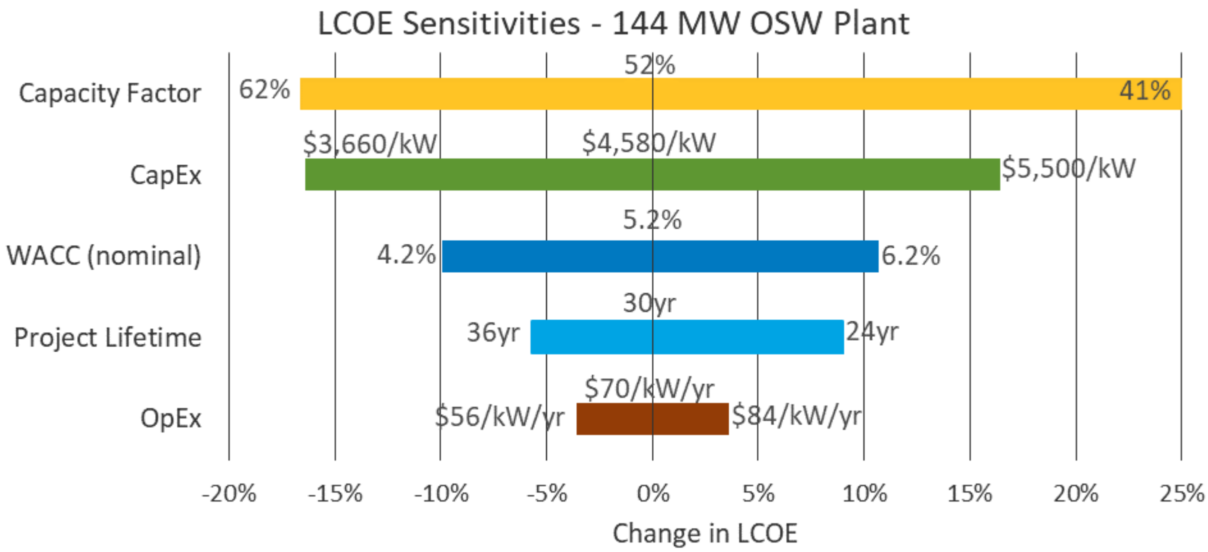

Figure 6. Change in LCOE relative to the baseline value for a 144-MW offshore wind power plant when varying financial parameters by ±20%. Labels on each horizontal bar indicate the parameter values that produce the baseline (center), low, and high LCOE.

3.2 Other Capital Costs

3.2.1 Transmission upgrades

The costs of required transmission upgrades for Full Deliverability were estimated by Quanta Technology (Daneshpooy and Anilkumar 2022). Their study identified the minimum transmission expansion that would be needed to deliver power from the proposed OSW plant under normal conditions as well as single- and multiple-fault contingencies, and calculated the cost of those upgrades based on PG&E's 2021 Proposed Generator Interconnection Unit Cost Guide (PG&E 2021). The resulting costs are summarized in Table 9. The cost ranges specified in two cases are due to an uncertainty with regard to how much of the cost will be borne by the interconnection customer.

Table 9. Transmission upgrade costs for Full Deliverability

OSW Capacity	*Upgrade Cost*
144 MW	$168 million to $238 million
288 MW	$329 million
480 MW	$591 million to $1.1 billion

3.2.2 Battery energy storage system

Scenarios incorporating energy storage assume a 4-hour, 15-MW BESS. The lithium-ion batteries used in the BESS are similar to those used in electric vehicles and the storage capacity of the modeled system is equivalent to 300 to 1,500 electric vehicle batteries available in 2021 (Alternative Fuels Data Center 2021). The system can store approximately 10% of the output of the OSW plant at full power and then discharging at 15 MW for up to four hours when fully charged. The capital cost of the BESS is approximately $11.8 million in 2030, based on projections by Cole and Frazier (2020). A variable operations and maintenance cost for the BESS of $33.75 per MWh (or approximately $700,000 annually) was applied (Daneshpooy and Anilkumar 2022). Note that the BESS configuration examined was chosen by the team at the Schatz Center for preliminary assessment. Other energy storage and power capacities may provide better economic results and may warrant further research.

3.3 Scenario Analysis

Scenarios with Full Deliverability include the cost of transmission upgrades that would be required to enable the full output of the modeled OSW plant to be delivered to electricity customers during winter and summer peak load conditions without overloading the local or regional grid. Transmission upgrades were found to be required for any plant capacity above 30 MW, which includes all of the Full Deliverability scenarios considered in this study. More details about the load cases and contingencies used for reliability analysis are provided in (Daneshpooy and Anilkumar 2022). A power plant with Full Deliverability could still experience curtailment during periods of low demand and high generation; however, no analysis was conducted for this study to identify possible curtailment levels. We report the net AEP for Full Deliverability scenarios under the assumption that there is no curtailment. Table 10 provides the total CapEx for four OSW plant capacities and the associated transmission upgrades as well as the levelized costs of energy and transmission. We find that the 288-MW plant obtains the lowest combined LCOE and LCOT at $87 per MWh. The 480-MW plant could achieve a slightly lower value if the transmission upgrade cost were limited to the lower end of the estimated range, however, its combined cost of energy and transmission is the highest among the studied plant sizes if the upgrade cost reaches the upper end of the range.

Table 10. Levelized cost of energy and transmission for Full Deliverability scenarios.

OSW Plant Capacity	*48 MW*	*144 MW*	*288 MW*	*480 MW*
OSW CapEx (million $)	$273	$661	$1,225	$1,935
Transmission CapEx (million $)	—	$168 to $238	$329	$591 to $1,123
OSW OpEx (million $ per yr)	$3.4	$10.0	$20.0	$33.3
Net AEP (GWh)	219	660	1,317	2,160
LCOE ($ per MWh)	$96	$80	$75	$73
LCOT ($ per MWh)	—	$12 to $17	$12	$13 to $25
LCOE + T ($ per MWh)	—	$92 to $97	$87	$86 to $98

The next set of scenarios examine alternatives to expanding transmission for plant capacities in the middle of the range of interest. The simplest alternative is to select Energy Only deliverability status, forgoing the opportunity to receive Resource Adequacy payments but also avoiding costs for transmission upgrades. Power flow analyses conducted as part of Task 2.2 indicated that generation capacity up to 174 MW could be interconnected at Humboldt Bay for Energy Only deliverability without triggering upgrade requirements under the baseline load case, or up to 231 MW in the augmented load case. Upgrade costs were not assessed for a 288-MW plant capacity with Energy Only deliverability. The expected curtailment and revenues for Energy Only scenarios were estimated using a production cost model (Daneshpooy and Anilkumar 2022). For the 168-MW plant, curtailment and revenues were also estimated for an augmented load case, which assumes a higher rate of electrification of heating and transportation in 2030. The third type of transmission alternative scenario includes a BESS that delivers energy to the grid during periods of high demand (high marginal price) and store energy from the wind turbines during periods of low demand, limited to no more than one cycle per day.

Table 11. Levelized cost of energy and revenue for Energy Only deliverability scenarios.

Scenario	*144 MW baseline load*	*144 MW + 15 MW, 4 hr storage*	*168 MW baseline load*	*168 MW augmented load*	*168 MW baseline load + storage*	*288 MW baseline load*
OSW + storage CapEx (million $)	$661	$672	$748	$748	$760	$1,225
OSW + storage OpEx (million $ per yr)	$10	$11	$12	$12	$12	$20
Curtailment (%)	4.4%	4.5%	6.0%	5.8%	5.5%	36.5%
Net AEP (GWh)	632	628	724	726	725	836
LCOE ($ per MWh)	$84	$86	$83	$83	$85	$119
Average LMP ($ per MWh)	$33	$36	$16	$22	$22	-$14
Revenue ($ per MWh)	$58	$63	$41	$47	$50	$11
Δ [Revenue – LCOE] ($ per MWh)	-$26	-$24	-$42	-$36	-$35	-$108

Table 11 summarizes the LCOE and revenue for six Energy Only scenarios. Compared to the full deliverability scenarios, CapEx and OpEx are the same for each plant capacity (with the exception of BESS costs for the cases with storage), but the net AEP is lower due to curtailment, leading to higher LCOEs. As plant capacity increases, the level of curtailment increases as local demand is met and export capacity is saturated, which also leads to a decrease in locational marginal prices (LMPs) and reduced revenue. The 288-MW plant sees the largest impacts from curtailment and low revenue, with total revenue far below the LCOE.

Comparison of the 168 MW baseline and augmented load cases illustrates the impacts of both curtailment and LMPs. Net AEP increases by 2 GWh in the augmented load scenario as curtailment is reduced, which leads to a $0.17 per MWh decrease in LCOE. At the same time, the average LMP is higher in the augmented load case because there is more demand for electricity, which leads to greater revenues.

The additional revenue from the BESS outweighs the initial system cost of the BESS for both the 144-MW and 168-MW plant capacities. The value of the BESS is greater in the 168-MW scenario, in which the OSW plant generates more energy and encounters grid constraints more frequently, providing more opportunities for the BESS to shift energy delivery to match demand and mitigate curtailment. Overall, however, the effect of lower LMPs in the production cost model results in the most favorable revenue-to-LCOE relationship for the 144-MW plant with battery energy storage.

Tax incentives can significantly impact the financial viability of a project. The tax credits available for wind energy have changed several times in the past decades and the level of tax credits that could be claimed in 2030 is uncertain. Table 12 compares three possible tax situations for a 144-MW offshore wind plant: no tax credit, a production tax credit (PTC) with a value of $25 per MWh, and a 30% investment tax credit (ITC). A wind plant owner cannot claim both the PTC and the ITC for the same project, so we apply only one type of tax credit in each scenario. We calculate the value of the ITC from the initial CapEx. The revenues for the Energy Only scenarios in Table 11 assume a $25 per MWh PTC, which allows the generator to accept an hourly LMP as low as -$25 per MWh. Without the PTC, the generator's minimum LMP increases to $0 per MWh and the offshore wind plant sees increased curtailment. The LCOE for scenarios with the ITC incorporates the value of the tax credit, accounts for any change in curtailment (for the Energy Only scenario), and increases the nominal WACC from the baseline value of 5.2% to 6.6% (real WACC increases from 2.6% to 4.0%). The change in WACC reflects an increase in the proportion of equity financing; for more detail on the development of the financial assumptions see Feldman et al. (2020).

Table 12. Impact of tax credits on cost and revenue for 144-MW plant capacity with Full Deliverability (FD) and Energy Only (EO) deliverability status

Scenario	*FD No Credits*	*FD 30% ITC*	*EO $25 per MWh PTC*	*EO 30% ITC*	*EO + Storage + PTC*
AEP_{net} (GWh)	660	660	632	555	628
Curtailment (%)	0%	0%	4.4%	16%	4.3%
LCOE ($ per MWh)	$80	$65	$84	$78	$86
Revenue ($ per MWh)			$58	$40	$63
Δ [Revenue – LCOE] ($ per MWh)			-$26	-$38	-$24

In Table 12, the lowest LCOE is obtained for the Full Deliverability with 30% ITC scenario. The impact of curtailment on LCOE can be seen by comparing the Full Deliverability and Energy Only ITC cases: annual curtailment of 105 GWh leads to an increase of $13 per MWh in the cost of energy. Among the Energy Only scenarios, the ITC scenario has the lowest LCOE, but the overall revenues are lower than those obtained in the PTC scenarios because of the additional 80 GWh of curtailment.

4. DISCUSSION

In this analysis we evaluate the costs of offshore wind energy in the Humboldt Wind Energy Area and consider alternatives to transmission upgrades. We examine plant capacities of 144 to 480 MW in Full Deliverability, Energy Only, and Energy Only with BESS.

4.1 Scenarios

Based on the Full Deliverability scenarios shown in Table 9, we find that the 288-MW plant has the lowest combined LCOE and LCOT of $87 per MWh. Total wind plant CapEx decreases on a per-kW basis as plant capacity increases (Figure 3). While this drives the trend of lower LCOE with increasing plant capacity (Figure 5), these savings are offset by higher costs for required transmission system upgrade costs when the plant capacity reaches 480 MW.

The Energy Only alternatives shown in Table 10 have higher LCOEs than their equivalently sized Full Deliverability counterparts because their energy output is reduced by curtailment. However, the LCOE of the 144-MW Energy Only scenario is lower than the LCOE + LCOT of the 144-MW Full Deliverability scenario, and the 168-MW Energy Only scenarios have marginally lower LCOEs than the corresponding 144-MW scenarios. At 288 MW, the level of curtailment is much higher, as is the LCOE. Larger plant capacities face greater curtailment because local electricity demand is met and the ability to deliver energy to the rest of the California grid is constrained. This local saturation depresses the locational marginal prices, reducing revenues for larger plant capacities. We use the difference between wind farm revenues and cost (revenues per MWh – LCOE) as a proxy for profit. All plant capacities have a negative difference, indicating that revenues do not exceed the cost of the wind farm.

Energy Only scenarios that include the addition of a 4-hour, 15 MW BESS or augmented (increased) load perform better in terms of revenues and revenues – costs than their baseline load counterparts. This is due to the ability to sell energy at higher prices during times of day when demand is high and indicates that the BESS adds more value than it costs for the plant capacities considered. This study only considered a single capacity and storage duration for the BESS. Additional analysis would be required to identify an optimal BESS size that could produce more revenue.

With the available information, the key dynamics illustrated by the above scenarios appear to be:

- Lower power plant costs per MWh (LCOE) for larger offshore wind plant capacities
- Higher transmission costs per MWh (LCOT) for the smallest and largest plants
- Suppression of revenue for Energy Only plants as capacity increases, caused by transmission constraints and local energy market saturation
- Lower LCOEs for the 144-MW and 168-MW Energy Only scenarios than the combined LCOE + LCOT of the 144-MW Full Deliverability scenario
- Increased revenue in Energy Only scenarios with BESS or Augmented Load.

It is important to note that even though the floating offshore wind cost results presented in Section 3. for the year 2030 were obtained using a conservative deployment assumption (4.9 GW) for the learning curve, the underlying learning rate was derived based on commercial-scale fixed-bottom industry cost data. This means that the cost reductions may be overstated because the commercial-scale fixed-bottom projects benefit from more mature supply chains than would a pilot-scale floating project in Humboldt.

4.2 Distribution of Costs and Benefits

Offshore wind energy projects accrue different costs and benefits from the perspective of different stakeholder groups. Revenues and LCOE are relevant to developers and project owners, while local residents may be more strongly impacted by job creation, infrastructure investment such as port and transmission upgrades, tax streams for different levels of government, and “ripple effects” from increased local spending. It is important to note that cost of producing energy at a wind plant (often expressed as

LCOE) can be different than the price that a plant owner receives (e.g., the strike price or PPA price). Both variables may be different than the price that ratepayers are charged by a utility or community choice aggregator. Ratepayers are affected by large-scale transmission infrastructure upgrades, which are usually paid for in California using rate-based funding such as Transmission Access Charges (Hackett and Anderson 2020a). Daneshpooy and Anilkumar (2022) identified that up to 174 MW of offshore wind could be built in Humboldt without triggering additional transmission infrastructure upgrades, but also found a decreasing trend in LMPs (and a corresponding decrease in project revenues) for plant capacities between 144 MW and 288 MW.

Jobs creation and economic development was the second most frequently mentioned benefit of an offshore wind energy project (after emissions reductions) in stakeholder interviews and public meetings conducted in the Humboldt region by Emery et al. (2020). Hackett and Anderson (2020b) estimated that the construction of an offshore wind plant in the Humboldt WEA could result in between $330 million and $550 million of economic outputs in the state of California and between 1,600 and 2,700 new full-time-equivalent job-years for plant capacities between 48 MW and 144 MW. Those figures represent the bulk of the spending and job creation, which occurs during the construction phase of a project. They estimated additional operations and maintenance economic impacts of roughly $3.2 million to $9.5 million annually, with the creation of the equivalent of 26 to 80 new full-time jobs for the same plant capacities (Hackett and Anderson 2020b).

Job creation and economic impacts were estimated at the state level, without assessing the regional distribution. It is reasonable to assume that a significant portion of the construction and operations jobs would be in the proximity of the wind farm in question. That said, the spatial distribution depends on the ports being used during the construction and operations phases of the project as well as the level of component manufacturing or assembly taking place in the region. The level of construction of other offshore wind projects along California's north coast and the southern coast of Oregon could also impact the amount of supply chain and manufacturing investment the region attracts.

Required port and harbor upgrades discussed by Porter and Phillips (2020b) include high bearing capacity wharf area, dredging, yard ground improvements, connections to utilities and roads, and an O&M vessel pier. The cost of upgrades to support offshore wind projects of up to 150 MW was estimated to be between $130 million and $200 million. Those port improvements would likely provide local co-benefits to other users of the port including fishermen, recreational boaters, commercial shipping vessels, and the Coast Guard (Hackett 2020). This investment could provide incentives for existing industries (aquaculture and wood product shipping) to expand, or to new industries to relocate (Hackett 2020).

It may be challenging to attract an offshore wind developer to build a single project on the scale of 150 MW without a "pathway to scale" for a future larger project. While developers are usually interested in the profitability of the wind farms they build, they may consider a pilot project an investment opportunity to test technologies, build relationships and establish a foothold in an emerging offshore wind market. A larger project, on the order of 1 GW or more, would offer greater potential for economic viability and make a larger contribution to California's clean energy goals under SB 100 (De Leon 2018; Hackett and Anderson 2020a). Larger projects would also require significant investment in additional transmission capacity and have more substantial impacts (both positive and negative) on the local community.

Future work could include revenue modeling for the Full Deliverability scenarios, including Resource Adequacy payments, to paint a more wholistic picture and allow for a more direct comparison between scenarios. This could involve looking at power purchase agreement structures and possible partnerships between the project developer and a community choice aggregator. Another direction for future work would be to expand the investigation of BESS scenarios to identify the optimal storage capacity to maximize revenue for a given OSW plant size.

5. CONCLUSIONS

This report identifies several options for developing a small offshore wind plant in the Humboldt WEA that result in lower costs than upgrading transmission to provide Full Deliverability. The cost of transmission upgrades increases our estimates of LCOE for wind power plants with Full Deliverability by 15% to 34%. Based on the curtailment and revenue estimates from Task 2.2, LCOEs for plant capacities of 144 and 168 MW with Energy Only deliverability are lower than the combined cost of energy and transmission upgrades for a 144-MW plant with Full Deliverability. The addition of a battery energy storage system increases revenue for the plant sizes considered, with the 144 MW + storage scenario producing the most revenue relative to LCOE.

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