California North Coast Offshore Wind Studies

Economic Viability of Offshore Wind in Northern California

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EXECUTIVE SUMMARY

The objective of this report is to model the potential economic viability of several offshore wind (OSW) farm scenarios sited offshore of northwestern California and served by the Port of Humboldt Bay, California. Broadly speaking, economic viability refers to the prospects for a wind farm project to successfully attract private-sector investment for wind farm buildout and commercial operation. The scenarios include two sites, both of which occur in federal waters – one the BOEM call area offshore from Humboldt Bay, California, and the second a notional alternative site offshore from Cape Mendocino, California. Scenarios also include three farm sizes ranging from 44 to 1,836 megawatts (MWs). As large-scale transmission infrastructure upgrades are usually paid for in California using rate-based funding such as Transmission Access Charges (TACs), rather than power purchase agreement (PPA) prices, transmission upgrade costs were not included in the economic viability analysis, but total transmission improvement costs are reported and discussed. In particular, the total capital cost for necessary transmission improvements scales directly with OSW farm size, with the largest farm size (1,836 MW) scenarios requiring an estimated $1.40 – 4.47 billion in transmission investment. The higher end of the range represents a subsea cable option for moving energy from generation to load centers in the San Francisco Bay Area.

Economic viability is modeled using the most current available version (2019.12.2 Beta) of the System Advisor Model (SAM) developed and distributed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). The analysis makes use of default parameters built in to SAM and customized parameters and elements from the OSW cost model developed by the Schatz Center project team. Key customized parameters from that cost model include capital expenditures ("CapEx") and operating expenditures ("OpEx"). These OSW cost model elements (all in constant 2019 dollars and adjusted for scenario construction start dates) were estimated by the project team using both bottom-up modeling as well as cost factors drawn from the literature. Other customized elements include a weather data file for wind resource at the sites under study, and specifications for a 12-MW turbine system.

Two financing structures were studied – a PPA single-owner project and a PPA sale-leaseback arrangement. In the assumed absence of federal production or investment tax credits (PTC, ITC) for new OSW projects in the mid-2020s, no tax equity "flip" structures were considered. As PPA prices are not readily available, instead the project team set an internal rate of return (IRR) target of 11% by year 20 of the project, and had SAM estimate a real levelized PPA price necessary for the project to deliver the target return. Analysis of SAM outputs indicate that only the largest farm size (1,836 MW) scenarios under study, using a single-owner financing arrangement, have economic viability potential, meaning that the estimated real levelized PPA price is roughly within range of market potential. Factors such as resuming the availability of federal tax credits, sharply increasing demand for renewable energy, or reduced project costs (such as from technology experience linked to expanded installed capacity) would improve the economic viability of offshore wind farms in northern California. Floating-platform OSW project cost reductions lag fixed-bottom OSW project costs by 5-7 years, and are expected to eventually converge (Musial, 2020).

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1. INTRODUCTION

The objective of this report is to model the potential economic viability of several offshore wind farm development scenarios sited offshore of northwestern California and served by the Port of Humboldt Bay, California. Broadly speaking, economic viability refers to the prospects for a project to successfully attract private-sector investment for wind farm buildout and commercial operation. Economic viability is modelled using the most current available version (2019.12.2 Beta) of the System Advisor Model (SAM) developed and distributed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). SAM is a techno-economic computer model that calculates performance and financial metrics of renewable energy projects, including offshore wind farms (Blair et al., 2018).

We begin the chapter with a discussion of the methods and approaches used in the analysis, including a summary of how the SAM model works, the customized scenario inputs we developed, and the financial and other types of analysis we employed. We then summarize the results of the analysis and provide concluding comments.

2. METHODS AND APPROACHES

In the analysis that follows we draw upon project scenarios for various configurations of a commercial offshore wind (OSW) farm sited offshore of northwestern California and served by the Port of Humboldt Bay, California. The OSW farm is assumed to sell energy to load-serving entities by way of a power purchase agreement (PPA). This introductory description closely follows Blair, et al. (2018). Generally speaking, renewable energy projects sell electricity at a fixed price with optional annual escalation and time-of-delivery (TOD) factors. For such projects, SAM derives a number of financial metrics, including:

- Levelized cost of energy
- PPA price or internal rate of return (IRR)
- Debt fraction or debt service coverage ratio

SAM can either calculate the IRR based on a power price one specifies or calculate the PPA price based on a target IRR that one specifies. As PPA price data are proprietary and not available for this analysis, we took the approach of specifying an IRR (the 11% SAM default value) and having SAM estimate the implied required PPA price schedule.

SAM calculates the levelized cost of energy (LCOE) from after-tax cash flows, so that the LCOE represents the cost of generating electricity over the project life. As Blair, et al. (2018) note, project annual cash flows relevant to a commercial OSW farm selling energy through a PPA include:

- Revenues from PPA-mediated electricity sales
- Wind farm capital costs and operating, maintenance, and replacement/repair costs
- Loan principal and interest payments
- Tax benefits and liabilities (accounting for any available tax credits for which the project is eligible)
- Investor's IRR requirements

The SAM financial model can account for a wide range of incentive payments and tax credits.

SAM requires input data to describe the performance characteristics of physical equipment in the system, as well as project costs and financial assumptions. SAM is available from the NREL website and operates as a desktop computer application. As noted, it comes with default input values, and tools for downloading some inputs from online NREL databases. SAM also requires a weather data file as input to describe the renewable energy resource and weather conditions at a project location.

2.1 Project Assumptions and Parameters

A total of 5 scenarios were developed by the Schatz Center project team for SAM analysis of the economic viability of OSW farms based near Humboldt Bay, California. These scenarios include the following variables:

- Location: The BOEM call area in federal waters offshore from Humboldt Bay, California (HB) and a notional alternative offshore site for comparison purposes located in federal waters offshore from Cape Mendocino, California (CM). Both location scenarios are assumed to use the Port of Humboldt Bay for construction, and for maintenance, repair, and component replacement support during OSW farm operations.
- Scale: 48, 144, and 1836 MW (HB); 144 and 1836 MW (CM).

The resulting scenarios for the economic viability analysis have the following abbreviated names (Table 1):

Table 1. Naming convention for offshore wind scenarios.

Abbreviated Name	*Wind Farm Capacity*	*Location*
HB-48	48 MW	Humboldt Bay
HB-144	144 MW	
HB-1826	1,836 MW	
CM-144	144 MW	Cape Mendocino
CM-1836	1,836 MW	

SAM provides parameter default values as well as a library of weather files, turbine systems specifications, and other relevant elements of analysis. SAM allows users to develop customized weather data, system component files, and parameters for their projects as well. Accordingly, the project team used the following customized inputs:

- Weather data for the wind resource, specifically created for the two scenario locations, were extracted from the National Renewable Energy Laboratory's WINDToolkit (Draxl et al., 2015).
- 12-MW turbine specifications, including hub height, rotor diameter, and turbine power, are defined from standard turbine parameters published by NREL (Musial et al., 2019a) and from General Electric (GE) turbine specifications (GE, 2020). This turbine specification was added to the SAM turbine library.
- Balance of system elements, including a floating semi-submersible platform, OSW farm electrical system (including array cables, export cable, substation, and grid connection), mooring system, and other ancillary elements based on developer input and assumptions in Musial, et al. (2019a).
- Capital cost (“CapEx”) and O&M cost (“OpEx”) factors originating from a custom project cost model developed by the Schatz Center project team for each scenario under analysis. The cost model features component-level bottom-up elements as well as cost factors and was developed from published scholarly works and technical reports, expert input, and feedback from OSW developers. All costs are in constant 2019 dollars and adjusted for each scenario’s assumed (approximately 2024) construction date. Where possible, cost model outputs were benchmarked using parameters closely matching the 600-MW Site 5 study scenario (south Oregon OSW site offshore of Port Orford, Oregon) modeled by Musial, et al. (2019a).
- The spacing between each turbine is 7 times the rotor diameter in the East-West direction and 10 rotor diameters in the North-South direction. The turbines are arranged in rows that are offset perpendicularly to the prevailing winds (turbine layouts for each scenario are described in more detail in Severy and Garcia (2020)).

Note that OSW farm operations modeled here will require substantial transmission infrastructure investments to move energy to load centers. The cost of such transmission infrastructure projects in California is usually paid for using rate-based funding such as transmission access charges (TACs) -- volumetric fees assessed on energy consumption for using the transmission grid controlled by the California Independent System Operator (CAISO). Under the ISO tariff definition, the TAC point of measurement is currently assessed at end-use customer meters on gross load as measured by MWh's of metered customer usage (CAISO, 2017). Substantial new transmission projects in California are approved by the CAISO, which also approves a transmission project sponsor to finance, construct, own, operate and maintain new transmission paid for by TAC assessments.

In cases where multiple generators develop renewable energy facilities in locations underserved by transmission, and the renewable energy is required to meet California's Renewable Portfolio Standard (RPS) requirement, CAISO developed the location constrained resource interconnection (LCRI) policy. Under the LCRI, generators that interconnect to the grid are responsible for paying a pro rata share of the going-forward costs of the line (through TACs) until the line is fully subscribed and the transmission owner is "re-paid" for its initial investment (Fink et al., 2011).

As transmission is usually paid for by a TAC revenue stream rather than from PPA prices, and transmission typically has a much longer service lifetime than generation, transmission is not included in CapEx and OpEx used in the SAM project economic feasibility analysis. The assumption is that CAISO and other entities will approve required transmission infrastructure investment that will have its costs recovered by a TAC assessment. That said, we do report total capital-cost estimates (from PG&E and Mott Macdonald (subsea cable)) for transmission upgrade estimates, as financing these transmission investments is a necessary condition for OSW farm development in waters offshore from northern California.

SAM default values were used for all other required simulation assumptions and parameters. Among the more prominent of these are a 25-year project life; 2.5% inflation rate; 6.5% real discount rate; 9.06% nominal discount rate; 1% PPA escalation rate; 11% IRR target by project year 20; and a debt service coverage ratio (DSCR) of 1.3, used to determine the debt component of single-owner project financing (note that DSCR is the ratio of net operating income to required debt service, a prominent benchmark for an entity's capacity to support debt (and lease) payments).

SAM allows users to select from a number of different assumed financing and ownership structures for simulation analysis. In this study, we considered two alternatives:

- A PPA single-owner project with financing deriving from a mix of debt and equity determined by the SAM default DSCR of 1.3.
- A PPA sale-leaseback project. In this structure, the owner sells the wind farm to a tax equity investor that then leases it back to the previous owner. The tax equity investor is then acting as the lessor, with the previous owner being the lessee. The lessor receives cash rent and the tax benefits, and the lessee receives the wind farm's operating profit. A sale-leaseback arrangement enables a corporation to access more capital than traditional financing methods. When the property is sold to an outside investor, the corporation receives 100% of the value of the property, whereas traditional loan financing is limited to a loan-to-value ratio or debt-coverage-ratio.

With projected commercial operation dates (CODs) of 2026 or 2028 (1,836 MW scenarios), and uncertainty regarding possible renewal of investment or production tax credits, the economic analysis here assumes no applicable federal tax credits such as the ITC or PTC. Modified accelerated cost recovery system (MACRS) depreciation and bonus depreciation is assumed for all scenarios. As a result, the tax benefits received by the lessor in a sale-leaseback structure is limited to depreciation.

As specific PPA price schedules for market-viable projects prevailing in the wholesale electricity market in California are proprietary and unavailable to the project team, instead of specifying a PPA price schedule and solving for IRR, we employed SAM's default 11% IRR target and used SAM to solve for the implied PPA price schedule.

2.2 Notional viability threshold

Economic viability is assumed to reflect a reasonable likelihood that a project can successfully attract private investment capital for development and operation. Recall we use SAM to solve for the minimum required PPA price schedule to deliver a specified IRR. The analysis is deterministic, and thus does not reflect the usual elements of investment risk. Inherently riskier projects must pay a higher expected return to attract investors who have an opportunity cost of capital based on other project investment opportunities available in the market. Thus, viability is a fuzzy target at this level of model abstraction.

In the present modeling exercise, PPA price is the sole source of revenue for an OSW project. Aligned with that, SAM derives a minimum PPA price schedule necessary for a project to generate an 11% IRR. Accordingly, the question of economic viability in this analysis is determined by whether the required PPA price schedule generated by SAM reflects prevailing PPA contract prices for other renewable energy projects competing to contract with a load-serving entity. We briefly offer several recent analyses of prevailing PPA contract prices below.

Wiser and Bolinger (2018) provide information on PPA prices (in constant 2018 dollars) for wind energy in the US. Wiser and Bolinger report steadily declining levelized real PPA prices in the US since approximately 2009 - 2010. No PPA executed since 2013 in the western US had a levelized real price above $80/MWh, and no PPA executed since approximately 2015 in the western US had a levelized real price above $60/MWh. Note that the PPA prices in their sample were reduced by the receipt of state and federal incentives, and Wiser and Bolinger report that the levelized PPA in their report would be at least $15/MWh higher without the federal tax credits or treasury grant. Thus, to provide comparability with the present study, an un-subsidized real levelized PPA price of approximately $80/MWh appears to be an upper bound. The California Independent System Operator (CAISO) reports the average wholesale electricity price in California in 2018 was $50/MWh (CAISO, 2019).

Bolinger, et al. (2019) provide information about real levelized PPA prices (in constant 2018 dollars) for utility-scale solar PV energy (bundled with renewable energy credits (RECs) where relevant) in the US. The goal of Bolinger and colleagues' report is to estimate how much post-incentive revenue a utility-scale solar project requires to be viable. While the present study is of course an OSW project assumed not to benefit from federal tax credits, to the extent that California utilities procure renewable energy to meet state RPS requirements, land-based wind and solar PV serve as substitutes, and as such, there should be a degree of comparability in PPA prices. The Bolinger, et al. report shows real levelized utility-scale solar PV PPA prices in California trending between approximately 25 to $50/MWh since 2016. While not a primary focus of the present study, Bolinger and colleagues also note that an increasing number of solar PV projects are bundled with battery storage, paid for either through a bundled PPA price or by way of capacity payments. Note that as with Wiser and Bolinger (2018), these PPA prices are reduced by federal incentives, and it is unlikely that an un-subsidized price would be any higher than that reported above for wind energy in California.

Beiter, et al. (2019) provide an analysis of PPAs for energy and RECs between the planned Vineyard Wind LLC wind farm and electric distribution companies in Massachusetts. Importantly, Beiter, et al. also identify additional external revenue streams and project benefits that lead to a levelized revenue factor (described below) that exceeds the PPA price and helps support OSW project success. The Vineyard Wind LLC project (in progress; delayed) has potential to be the first utility-scale OSW farm in the United States. Beiter, et al. report a first-year PPA of $74/MWh ($2022, facility 1) and $65/MWh ($2023, facility 2), both with 400 MW capacity.

As noted above, Beiter, et al. (2019) also considered ITC benefits and anticipated external revenue stream sources beyond the PPA, such as from the ISO-NE forward capacity market. This bundle of PPA and REC revenue, tax credit benefits, and anticipated revenue from the sale of capacity were used to derive a levelized revenue of energy (LROE). Beiter et al.'s total calculated LROE for the Vineyard Wind LLC wind farm is estimated to be $98/MWh ($2018). Beiter, et al. note that this LROE estimate appears to be within the range of the LROE estimated for offshore wind projects recently tendered in northern Europe with a start of commercial operation by the early 2020s. Note that in the present analysis, no other revenue streams or federal tax credits apply. Therefore, the LROE from Beiter, et al. serves more as a rough benchmark for a required levelized real PPA price in the current SAM economic viability analysis.

Based on the recent past benchmark levelized PPA prices and LROE described above, it is likely that a California public utility seeking to contract for renewable energy would have more attractive, lower-priced renewable energy available if offshore wind energy were to require a levelized real PPA price above approximately $100/MWh in constant 2019 dollars (including the value of bundled RECs). That is not to say a project will be viable at any levelized price below $100/MW. Rather, the appropriate interpretation of this notional threshold is as follows:

- Levelized real PPA price from SAM > $100/MWh: Project is unlikely to be viable under current market assumptions
- Levelized real PPA price from SAM ≤ $100/MWh: Project may be viable under current market assumptions

This situation could certainly change if either the supply side or the demand side of the renewable energy market in California or the region were to change. This will be discussed in greater detail in the conclusion of this report. Further, many utility-scale solar projects are bundling some degree of battery storage, which reduces intermittency and meets resource adequacy requirements. As solar with energy storage becomes more common, it can provide a better economic comparison point because it can produce a similar generation profile to offshore wind.

3. RESULTS

We begin with cost model results by scenario, broken out by major component elements. Next, we consider key financial metrics for the single owner financing alternative, followed by the sales-leaseback financing alternative. We report Year-1 PPA price, real levelized PPA price, and real LCOE. We also provide information on the mix of debt and equity in the optimized SAM solution for each scenario.

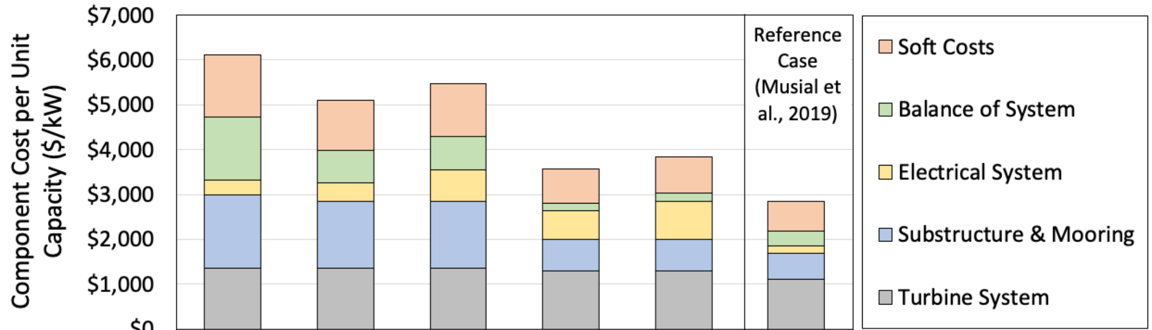
3.1 Wind farm estimates by major component elements

As previously noted, in the development of the cost model, we made use of a number of component cost assumptions from Musial et al. (2019a), though much of our cost model derives from original bottom-up modeling. When we performed benchmarking runs of our cost model using the 600 MW scenario parameters drawn from Musial et al.'s Study Site 5 scenario (south Oregon OSW site offshore of Port Orford), and adjusted for their 2032 COD date, our model's CapEx cost factor estimate was less than 1% below the CapEx value they reported. On a less comparable scenario-to-scenario basis, comparing Musial et al's Study Site 5 scenario for a 2027 COD date (which assumes 12 MW turbines and a 600 MW farm) with our CM 1836 scenario with a roughly comparable 2028 COD date, 12 MW turbines, but a farm size more than 3 times as large, our model's CapEx cost factor estimate was 1.6% higher than the value they reported.

O&M costs are somewhat more difficult to compare, as different projects have different distances to O&M ports, different port-area labor market conditions, different port tariffs, and different access to support vessels, leading to naturally different O&M costs. When we performed a benchmarking comparison as described above (again, assuming a later 2032 COD date), our OpEx cost factor estimate was $44.23/kW, compared to their estimate of $54/kW. Consequently, our OpEx estimate was about 18%

below that of Musial et al. (2019a). Comparing Musial et al's Study Site 5 scenario for a 2027 COD date (which assumes 12 MW turbines and a 600 MW farm) with our CM 1836 scenario with a roughly comparable 2028 COD date, 12 MW turbines, but a farm size more than 3 times as large, our model's OpEx cost factor estimate was 22% lower than the value they reported.

In Figure 1 we show the major components of CapEx by scenario. One can see that turbine cost factors show very modest economies of scale, whereas electrical array system cost factors (inclusive of costs for floating substation and export cable to landfall) display diseconomies of scale linked to the higher capacity array cables, export cables, and floating substation required when a larger number of turbines are interconnected. Also note that the notional Cape Mendocino site is farther from the port of Humboldt Bay and the landfall site for energy being moved from the wind farms, resulting in more export cable expenditure being required than for the HB scenarios.



	HB-48	HB-144	CM-144	HB-1836	CM-1836	Ref-600
Soft Costs	$1,387	$1,117	$1,186	$761	$807	$678
Balance of System	$1,392	$723	$735	$173	$181	$319
Electrical System	$332	$406	$705	$632	$837	$171
Substructure & Mooring	$1,630	$1,479	$1,479	$709	$709	$577
Turbine System	$1,366	$1,366	$1,366	$1,294	$1,294	$1,110

All values in $/kW

Figure 1. Major component costs of the CapEx per kilowatt ($/kW) for all offshore wind scenarios and a 600 MW reference case from Musial et al. (2019a) Oregon feasibility study.

In Table 2 we show estimated OpEx costs by scenario. As the notional Cape Mendocino site is farther from the port of Humboldt Bay than the BOEM call area, operations and maintenance (O&M) costs are slightly higher for the CM scenarios than for HB scenarios of equivalent capacity. One can also see very modest economies of scale for O&M costs.

Table 2. Estimated OpEx costs for each scenario in dollars per kilowatt per year for all offshore wind scenarios and a 600 MW reference case from Musial et al. (2019a) Oregon feasibility study.

OpEx Costs by Scenario	*HB-48*	*HB-144*	*CM-144*	*HB-1836*	*CM-1836*	*Ref-600*
Operations, *$/kW-year*	$30.48	$30.52	$31.07	$28.88	$29.40	$23.77
Maintenance, *$/kW-year*	$32.48	$32.35	$33.66	$30.27	$31.44	$21.46
OpEx Total, *$/kW-year*	$62.96	$62.87	$64.73	$59.15	$60.84	$44.23

3.2 Single owner

Key financial metrics improve as OSW farm size increases (Figure 2). Only the two largest scenarios – 1,836 MW farms in the BOEM call area or the notional Cape Mendocino alternative site – feature real levelized PPA prices that fall below the notional $100/MWh threshold for projects with the potential for being economically viable. Our SAM results are roughly comparable to the 600-MW Site 4 and 5 study scenarios modeled by Musial, et al. (2019a) for a 2027 COD date and comparable 12 MW turbines. In particular, Musial et al. report a real LCOE ($2018) for a 2027 COD date of $74/MWh for their lowest-cost Site 5 scenario offshore of Port Orford, Oregon, which features a 53% net capacity factor, while our lowest-cost CM-1836-SO scenario's real LCOE ($2019) is $78.90, at a 56.7% capacity factor. Musial et al. report a real LCOE of $87/MWh for their Site 4 scenario offshore of Coos Bay, Oregon with a 2027 COD date and a 46% capacity factor, which roughly matches up with our HB-1836-SO scenario's real LCOE ($2019) of $88.90/MWh and 47.5% capacity factor.

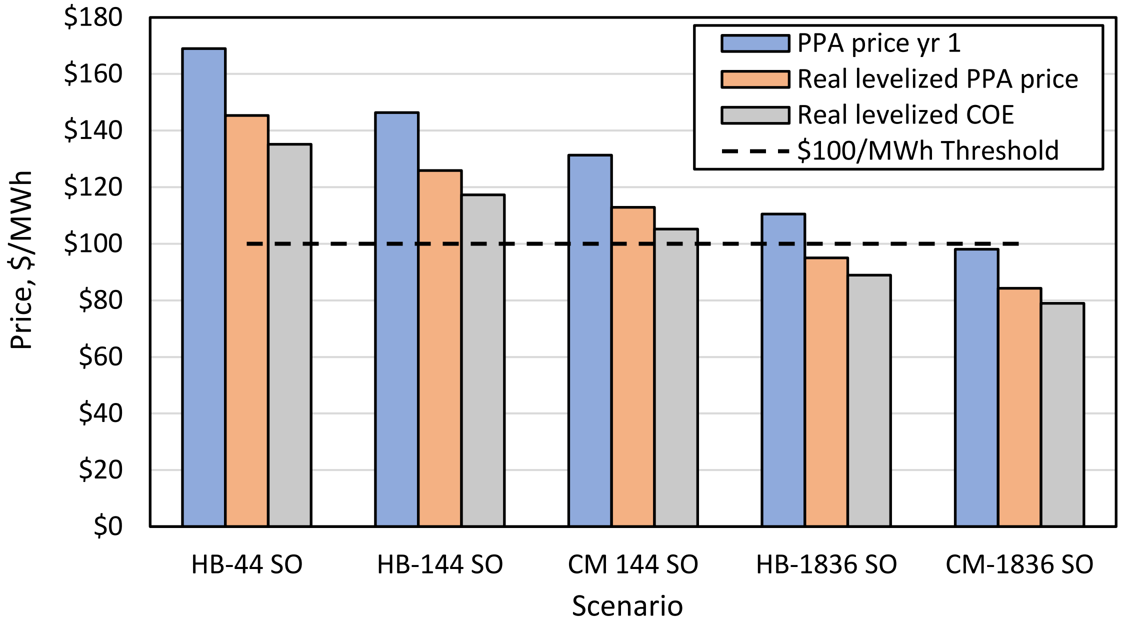


Figure 2. Financial performance metrics for five wind farm scenarios using single owner project financing.

From Table 3 one can draw inference as to why the notional Cape Mendocino site out-performs the BOEM call area. In particular, while the Cape Mendocino site requires roughly an additional half-billion dollars in net capital cost for the 1,836-MW scenario, the substantially higher capacity factor associated with its superior wind resource leads to the stronger financial performance of the notional Cape Mendocino site.

Table 3. Descriptive project financing measures for single owner financing.

Measure	*HB-44*	*HB-144*	*CM-144*	*HB-1836*	*CM-1836*
Capacity Factor	48.6%	48.1%	57.2%	47.5%	56.7%
IRR, End of Project	13.3%	13.3%	13.3%	13.3%	13.3%
Net Capital Cost ($ million)	$319	$798	$858	$7,150	$7,670
Equity ($ million)	$ 85	$212	$228	$1,880	$2,020
Debt ($ million)	$234	$586	$629	$5,268	$5,644

3.3 Sale-leaseback

As with the single owner financing alternative, key financial metrics improve as OSW farm size increases in the sale-leaseback financing option (Figure 3). Unlike the single owner financing option, none of the sale-leaseback financing scenarios fall below the notional $100/MWh threshold for projects with the potential for being economically viable.

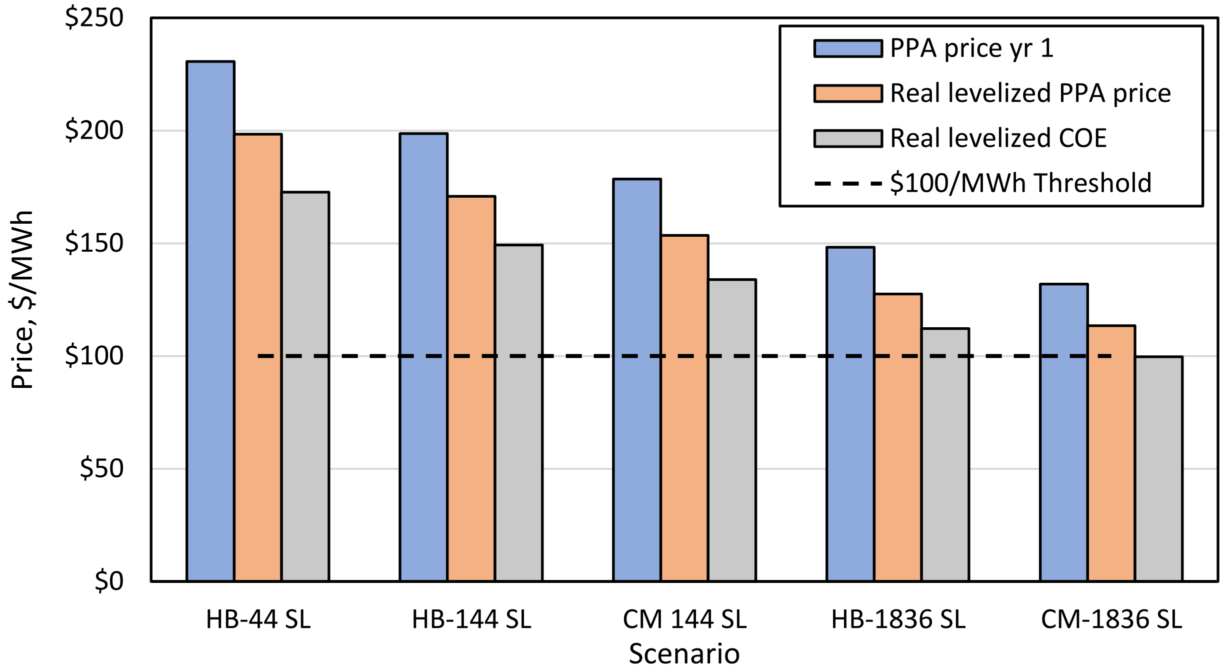


Figure 3. Financial performance metrics for five wind farm scenarios using sale-leaseback project financing

Note that in the sale-leaseback financing alternative in SAM, the program requires an investor IRR target and solves for PPA prices and other metrics. The default investor IRR target is 11% by Year 20 of the project. As a result, while investors with an 11% IRR target by Year 20 are assured their target is met (with a sufficiently high PPA price schedule), the developer IRR is solved for from the assumed investor IRR target. As a result, one can see in Table 4 that solution values for developer IRR by scenario are much weaker than for the investor.

Table 4. Descriptive project financing measures for sale-leaseback financing ($ million)

Measure	HB-44	HB-144	CM-144	HB-1836	CM-1836
Capacity Factor	48.6%	48.1%	57.2%	47.5%	56.7%
Investor IRR, end of project	11.8%	11.8%	11.8%	11.8%	11.8%
Developer IRR, end of project	5.5%	6.0%	5.8%	7.0%	6.8%
Sale of Property, $ million	$308	$770	$827	$6,881	$7,380

3.4 Transmission Infrastructure Upgrade Costs

As noted, transmission infrastructure upgrade costs, particularly involving substantial new transmission lines and substation development, are generally paid for by energy consumers by way of transmission access charges (TACs). Nonetheless, these upgrades are necessary for OSW farms to operate successfully in the waters offshore from northern California. Below we report estimated capital costs for these essential upgrades by scenario, rounded to the nearest million dollars. It should be noted that the upper end of the range of estimated capital cost is roughly estimated as twice the value of the lower range for the 48 MW, 144 MW, and 1,836 MW "East" and "South" alternatives. All terrestrial transmission pathway estimates were provided by PG&E; the subsea cable pathway estimate was provided by Mott Macdonald. The cost estimates were then adjusted, taking into consideration terrain, length of line, and the acquisition of land, which is represented by the black bar in Figure 4.

Note that the "East" pathway routes energy from Humboldt Bay to the transmission junction at the Round Mountain Substation, whereas the "South" pathway routes energy from Humboldt Bay to the Vaca-Dixon Substation junction. Also note that the cost of transmission improvements is assumed to be the same for OSW farms located in either the Humboldt Call Area or the notional Cape Mendocino area. This is because the cost of delivering energy from the wind farm sites to a shore-side Humboldt Bay Substation with the OSW export cable is already built into the cost for the OSW farms.

As one can see from Figure 4, the estimated adjusted costs of transmission improvements necessary to move energy from the OSW farms under study to load centers generally increases with assumed wind farm scale, as expected. The more energy that needs to be transmitted to load centers, the greater the capacity of transmission infrastructure that must be built and the greater the cost. One can also see that the adjusted cost of a subsea cable near shore is estimated to be approximately a billion dollars more than either the south or the east terrestrial transmission pathway. Additionally, the adjusted cost of a subsea cable far from shore is estimated to be almost a billion dollars more than a near shore subsea transmission pathway.

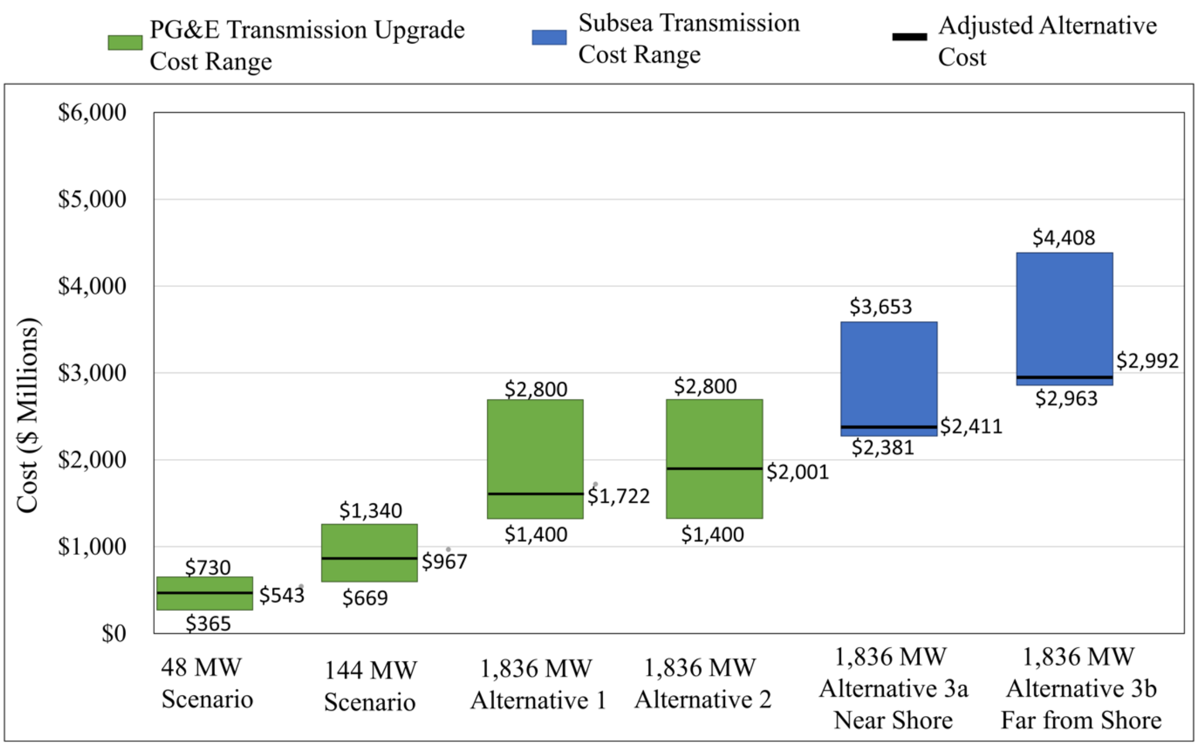


Figure 4. The adjusted values of transmission upgrade capital cost estimates from PG&E.

4. CONCLUSIONS

Only the largest of the OSW farm scenarios – CM-1836 and HB-1836 – using a single owner financing scheme, have real levelized PPA prices that fall below the $100/MWh notional threshold for OSW projects having potential to be economically viable ($78.90 and $88.90, respectively). In both cases these real levelized PPA prices are comparable to the LROE estimate from Beiter et al. (2019), but lie far above the approximately $40-60 per MWh values for western-region wind energy project real levelized PPA prices documented by Wiser and Bolinger (2018) for roughly 2015 - 2017 (and which are inclusive of revenue from REC credits, any relevant capacity payments, and federal tax credits). Note that roughly similar to lower-cost results can be obtained for utility-scale solar, a substitute for load-serving entities subject to RPS requirements (Bolinger et al., 2019). Wiser and Bolinger note that these reported real levelized PPA prices would be at least $15/MWh higher in the absence of federal tax credits. Thus, to make them roughly comparable to the current analysis in which these tax credits have expired, the range of observed wind farm PPA prices would be approximately $55-75 per MWh. One can see that even the very largest OSW farm scenarios investigated here require real levelized PPA prices well above these observed “market” PPA prices for 2015-17 in the western U.S. Moreover, the ability of a single owner to assemble the more than $7 billion in required project debt and equity financing to cover net capital cost may be optimistic.

Overall, one must conclude that even under the most favorable large-scale OSW farm scenarios, the market-based economic case for these projects is tenuous. This situation could certainly change if wind farm project costs were to decline; if additional revenue sources, tax credits or grants became available; or if underlying market demand for renewable energy were to change. As Beiter, et al. (2019) note, a market-rate PPA price (likely well below $100/MWh) bundled with one or more outside revenue streams such as capacity or REC payments, along with federal or state credits, could result in a levelized revenue of electricity (LROE, conceptually similar to the bundled real levelized PPA price in Wiser and Bolinger (2018) that is inclusive of all relevant external revenue streams and tax credits) sufficient to make a project competitive. Currently those outside revenue and benefit sources cannot safely be assumed to be available for the OSW project scenarios under study, but were they to be, then the resulting LROE (or bundled PPA price) would be the appropriate instrument for gauging viability. On the demand side, increasingly stringent RPS requirements placed on load-serving entities would likely increase market-viable PPA contract prices due to all the lowest-cost or most resource-rich renewable energy project opportunities having already been exploited. Moreover, smaller demonstration-scale OSW projects with grant or other government funding may be feasible in a non-market context. Floating-platform OSW project cost reductions lag fixed-bottom OSW project costs by 5-7 years, and are expected to eventually converge (Musial, 2020).

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APPENDIX A - COST ESTIMATION METHODOLOGY

The following appendix presents the methods used to develop the offshore cost model in support of the North Coast Offshore Wind Study carried out at the Schatz Energy Research Center. This cost model is customized to reflect specific project assumptions, scenarios, and locations. The project is assumed to occur in the waters off of Humboldt County, California, using 12 MW turbines for floating offshore wind farms ranging in size from 50 to over 1,800 MW nameplate capacity.

The purpose of the cost model is to provide insight into several economic performance metrics, broadly categorized as economic impacts to the State of California, and the economic viability of various scenarios. Economic impacts are the total number of new jobs in California and indirect economic output (in dollars) resulting from offshore wind farm development. Economic viability metrics include levelized cost of energy and power purchase agreement prices necessary to yield a target internal rate of return for wind farm investors and developers.

The cost model was developed as a sum of component costs under two broad categories, one-time capital costs and recurring operations, maintenance, and repair costs. The major components of the initial capital expenditures (Capex) are the turbine system; the substructure and mooring system; the electrical system; the installation costs; and the soft costs, which include development, construction financing, insurance, contingencies, leasing, commissioning, decommissioning, and a lease. The operational expenditures (Opex), include operations, maintenance, and repair costs. Each cost component is modeled in one of several ways, including bottom-up models, industry-standard factors, and expert estimates (Table 5).

Table 5: Overview of costs and methods

Category	*Method*	*Value*	*Note*
Component costs			
Turbine	Literature average	$1,480/kW	Adjusted for learning effects based on construction date
Substructure & Mooring System	Piecewise function from literature	Between $1,236 - $577/MW (2032 $)	Value changes based on wind farm scale
Port and Staging	Estimate from literature	$ 44/kW	
Electrical interarray cables	Optimized string and voltage layout to minimize cost	between $66-$79/kW	66 kV interarray cables
Electrical export cables	Optimized number of cables and voltage	between $611-$693/kW	66 kV for 48 MW farm; 132 kV for 144 MW farm; 275 kV for 1,836 MW farm
Ancillary electrical components	Required infrastructure based on design	Between $9.42 - $18.05/kW	Includes substation and substructure (as needed)
Development costs			
Engineering & management	Factor from literature	4% of total component cost	
Permitting & site characterization	Flat estimate from literature	$13,110,000	Same cost for all scales
Assembly and Installation	Based on assembly and installation time, vessel rate, vessel travel time, personnel wages, weather, and wind	Varies, $/kW	Includes 30% downtime due to metocean conditions; Assembly time based on operation videos
Transmission costs			
Transmission Upgrades	Project specific estimate from PG&E	varies	Pacific Gas and Electric Company (2020)
Soft costs			

Category	*Method*	*Value*	*Note*
Commissioning	Factor	1% of component costs	
Construction Insurance	Factor	1% of component costs	
Decommissioning Bond	Factor	15% of component costs	
Procurement contingency	Factor	5% of component costs	
Installation contingency	Factor	30% of installation cost	
Construction Financing	Estimate from literature	$ 118/kW	
Lease Price	Average of previous leases	$237/acre	
Operations costs			
Insurance	Estimate from literature	$ 31/kW	
Management & admin	Estimate from literature	$ 5.80/kW	
Lease fees	Calculated	$3.80-$4.60	Based on BOEM offshore wind documentation
Overhead	Factor	37.60% of wages	
Maintenance costs			
Corrective maintenance	Calculated based on failure rate, material costs, repair duration, # technicians required, vessel rate and travel, and personnel	$35.82-$36.74/kW	Range changes based on COD and location
Condition-based maintenance	Assumption	20% of corrective maintenance	
Calendar-based maintenance	calculated based on failure rate, material costs, repair duration, # technicians required, vessel rate and travel, and personnel	$3.21-$3.89	Assumed approximately 2 major replacements every 5 year and 2 minor repairs every year
* All values in 2019 US Dollars unless otherwise noted.			

Industry learning effects are estimated to adjust for future construction dates learning effects are estimated in terms of cost reduction percentages between 2019 and 2032 (Table 6). The estimates are based on the calculations from Musial et al. (2019a), which are drawn from an in depth cost-reductions pathways study done by InnoEnergy and BVG.

Table 6: Learning curve reductions as a percentage of project costs (adapted from Musial et al. 2019a)

COD	2019	2022	2027	2032
Development	0.00%	3.79%	6.68%	11.75%
Rotor Nacelle Assembly	0.00%	0.61%	9.45%	25.00%
Substructure	0.00%	0.77%	11.92%	31.52%
Foundation	0.00%	0.61%	9.47%	25.06%
Array Cable System	0.00%	14.12%	25.97%	46.81%
Export Cable System	0.00%	14.83%	27.34%	49.36%
Turbine Installation	0.00%	0.05%	8.02%	21.20%
Substructure & Foundation Installation	0.00%	0.09%	14.11%	37.33%
Operations	0.00%	22.32%	28.27%	41.93%
Maintenance	0.00%	24.76%	31.41%	46.69%
Gross AEP	0.00%	1.63%	2.19%	5.03%
Total Losses	0.00%	0.09%	1.19%	2.74%
CapEx	0.00%	6.76%	16.17%	32.67%
OpEx	0.00%	9.16%	14.84%	27.89%
AEP	0.00%	1.75%	2.40%	5.72%

Scale effects are modeled directly in the bottom-up models, which allows the scale effects to be reflected in the factor-based costs as well. In this project, scale effects refer to both the turbine scale and the total farm scale. For example, larger turbines (in terms of capacity) means that there are fewer turbines to install per unit capacity and thus installation vessel costs are lower. Larger farms mean that the power export cables can be more efficiently sized and thus electrical system costs are lower. Supply chain effects are outside the scope of this project.

The cost model is responsive to a variety of input parameters. Input parameters include farm scale (MW), turbine size (MW), capacity factor (%), farm area (acres), distance to port (km), distance to landfall (km), average water depth (m), commercial operation date (COD) (year), and substructure construction method (local or imported). Transmission upgrade costs are estimated by project partners (PG&E and Mott MacDonald) and included as a separate line item in the cost model. For the purpose of this project, a number of scenarios were assessed, with the input parameters summarized in *Table 7 and Table 8.*

Table 7: Input parameters for BOEM call area scenarios

Parameter	*units*	*B50e*	*B150e*	*B1800e*	*B1800s*	*B1800sub*
Wind Farm Capacity	MW	48	144	1836	1836	1836
Turbine Power Rating	MW	12	12	12	12	12
Capacity Factor	%	55	55	55	55	55
Wind Farm Area	acres	2,323	8,154	132,448	132,448	132,448
Distance to port	km	53	53	53	53	53
Distance to land	km	44	44	44	44	44
Average depth	m	800	800	800	800	800
COD	year	2026	2026	2028	2028	2028
Structure construction	-	import	import	local	local	local
Transmission route	-	east	east	east	south	submarine

Table 8: Input parameters for hypothetical Cape Mendocino area scenarios

Parameter	*units*	*M150e*	*M1800e*	*M1800s*	*M1800sub*
Wind Farm Capacity	MW	144	1836	1836	1836
Turbine Power Rating	MW	12	12	12	12
Capacity Factor	%	65	65	65	65
Wind Farm Area	acres	8154	123,553	123,553	123,553
Distance to port	km	95	95	95	95
Distance to land	km	88	88	88	88
Average depth	m	800	800	800	800
COD	year	2026	2028	2028	2028
Structure construction	-	import	local	local	local
Transmission route	-	east	east	south	submarine

A.1 Turbine

In this cost model, the turbine component includes the tower, rotor, nacelle, and all the internal electronics. The turbine cost is calculated as the average of recent literature estimates then adjusted to account for learning effects that would reduce costs (summarized in Table 6). To calculate turbine costs in $/kW, recent literature sources were gathered and converted to present dollars (2019 $) (Table 9). The average value from these sources was then projected into the future using the learning effects described in Table 6. The turbine cost estimate was calculated to be $1,480/kW of nameplate capacity.

Table 9: Turbine cost data

Source	*Cost, $/kW*	*Cost, 2019 $/kW*	*Turbine Size, MW*	*Dollar Vintage*
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
BVG (2019)	$ 1,333.33	$ 1,179.25	10	2018
Shafiee (2016)	$ 1,329.00	$ 1,430.14	5	2014
Myhr (2016)	$ 1,909.32	$ 2,087.08	5	2013
Musial (2016)	$ 1,583.00	$ 1,704.89	6	2015
JEDI default (n.d.)	$ 1,000.00	$ 1,110.50	n/a	2012
Stehly (2018)	$ 1,094.00	$ 1,133.93	2.32	2017
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
Valpy (2017)	$ 1,030.95	$ 1,068.58	6	2017
Costas (2015)	$ 1,532.34	$ 1,648.95	5.08	2014
Beiter (2016)	$ 1,583.00	$ 1,681.94	6	2016
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
Noonan (2018)	$ 1,408.45	$ 1,459.86	unknown	2017
Average	$ 1,412.80	$ 1,479.49	5.65	2015
Adjusted to COD 2026	$ 1,365.93		Learning effect is 8%	
Adjusted to COD 2028	$ 1,293.75		Learning effect is 13%	

The turbine model makes a number of assumptions. First, it assumes that cost (in $/kW) does not change with turbine size. This assumption is based on data analysis and Musial et al.'s note that "a higher turbine rating may not result in an increase in per-unit turbine capital expenditures (CapEx) ($/kilowatt [kW]) at all" (Musial et al., 2019b). Second, it is assumed that the market for fixed-bottom turbines and floating turbines is the same. This assumption is based on the small floating market during the study period and the lack of any indication from any manufacturers of movement toward a customized floating turbine. Recent press-releases from major manufacturers discuss improvements in turbine size, but no other significant deviation from the standard machine (GE, n.d.)(*Siemens Gamesa Launches 10 MW Offshore*

Wind Turbine; Annual Energy Production (AEP) Increase of 30% vs. Predecessor, n.d.). Third, it is assumed that east Asian manufacturing does not have a large effect on the prices of the world market due to the large East Asian pipeline.

There are a number of limitations with this method. First, it is only based on publicly available academic literature, with limited sources. Second, the industry has been changing rapidly, and turbine sizes have been rapidly increasing, so academic cost models written as few as 5 years ago were estimating costs for turbines that were less than half of the size of the turbines expected in the '20s. Therefore, the older academic literature is now outdated and cannot be the best estimate for turbines built 5-10 years in the future. Third, turbine costs are determined with project-specific contracts that depend largely on the complex supply chain.

A.2 Substructure and Mooring System

The cost model for the substructure and mooring system is based on industry expert cost estimates. Two recent cost estimates from Musial et al. (2019a) for a 24 MW and 600 MW wind farm were used to establish a piecewise function to estimate costs at any scale (Figure 5). Costs are assumed to decreased linearly with farm scale for farms between 24 MW (the lower point) and 600 MW (the upper point), and that the majority of the scale effects have been realized by the time a farm is 600 MW (40 x 15 MW turbines), and that cost remained relatively constant as farms grew beyond 600 MW, see Figure 5. Musial et al. (2019) reported the costs with a 2032 COD. In order to apply their costs to this model, the learning effects from Table 6 were used to adjust the values to the appropriate COD for the project scenario.

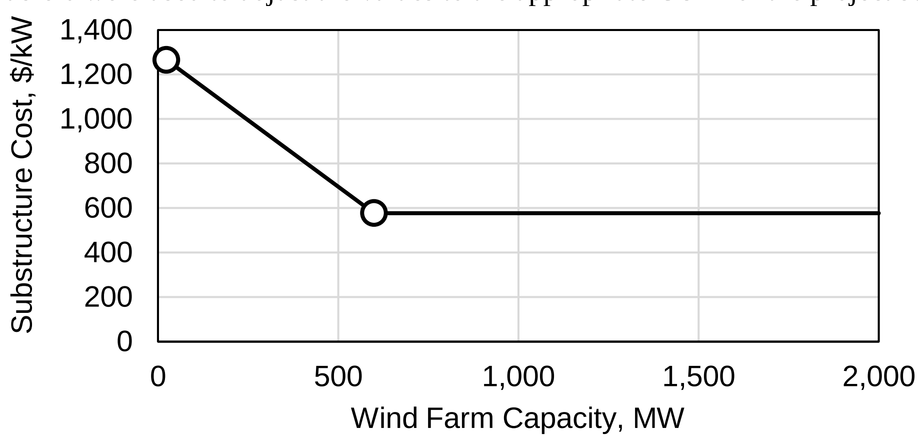

Figure 5: Substructure and mooring system cost as a function of farm scale

There are three primary assumptions built into this cost model. First, it is assumed that cost scales linearly with farm size. Cost effects based on turbine size and prevailing metocean conditions (severe or mild, hurricane risk, etc) are not included here. Second, it is assumed that all scale-based cost reductions have been achieved at scales over 600 MW. There may be further cost reductions beyond this scale, but without supporting data, a flat $/kW was used for wind farms above 600 MW. Finally, it is assumed that different substructure types (for example, concrete or steel, barge or lattice, etc) have the same cost.

The input data are based on a 2019 NREL report on offshore wind in Oregon (Musial et al., 2019a). This report included an analysis of the effect of scale on a farm off the coast of Oregon, and reported the cost of the substructure and mooring system. The weather regime in Oregon is similar to Northern California (classified as severe in terms of parameters that effect offshore wind)(Dewan & Stehly, 2016), and the site is only slightly shallower, so this is assumed to be the most relevant cost estimates for substructures. The COD for these estimates is 2032, which was addressed based on learning effects cost reduction estimates in Musial et al. (2019a). The substructure cost estimates from Musial et al. (2019a) are for 15 MW turbines, instead of 12 MW turbines like the present analysis. However, since the costs are provided on a $/kW basis, and the substructure will be similar, the cost are not adjusted by turbine size.

A.3 Electrical System

The electrical system component cost is estimated as the sum of each subcomponent cost including: interarray power cables (within the wind farm); export power cables (connecting wind farm to shore); offshore converter substations (connecting interarray and export cables); and ancillary components. The lowest cost electrical system design was selected for each project scenario, based on the calculation of capacity requirements for wires and components, then estimating total farm costs for a variety of designs, and finally selecting the lowest cost factor ($/kW) for each overall scenario. Cost reductions due to learning effects are applied to the estimated cost to adjust for the appropriate commercial operation date.

Cable costs are calculated using historical submarine cable cost literature relating ampacity and price (see Figure 6) projected onto available cable sizes, plus a price premium. Cable capacity is based on a recent manufacturer catalog relating cable size, in cross sectional area (mm2), to ampacity. Power capacity is calculated based on Equation 1, where $\cos \emptyset$ is the power factor, which is assumed to be 0.95 based on the minimum acceptable power capacity for a wind farm connected to the grid (Brownell et al., 2005). The price premium depends on the size and type of cable: the price premium for array cables is 15% and the price premium for a dynamic export cable is 100% (Robert Weeks, personal communication, October 2019; Bill Wall, personal communication, October 2019).

Equation 1: $$P = IV\sqrt{3} * \cos \emptyset$$

A.3.1 Interarray Cables

Array cable costs are calculated based on a variety of layouts for each farm that vary the number of turbines per string, assuming the turbines are daisy-chained together. In each layout, the minimum cable size between each turbine is determined based on the power through each cable. The arrays are limited to two cable sizes, and the total farm cost is calculated for each option, based on the number of sections of each cable size, and the unit cost of the cable.

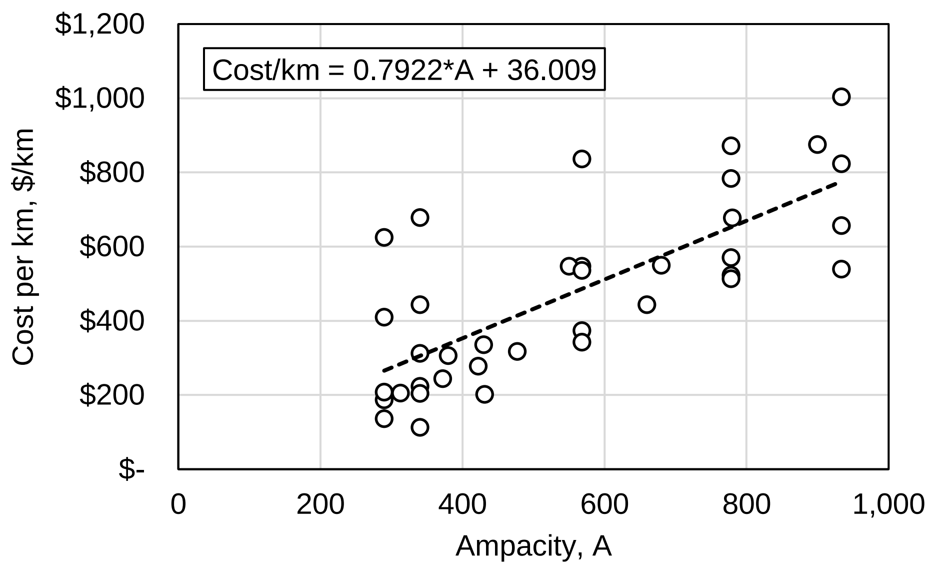

Figure 6: Array cable cost as a function of ampacity

For example, in the 48 MW farm, there are four turbines. You could have one string of four turbines, two strings of two turbines, or four strings of one turbine (attaching to an offshore substation). If you have four strings of one turbine, you would need four lengths of 95 mm^2 cable. If you have two strings of two turbines, the maximum power through the string is still within the capacity of the 95 mm^2 cable, so you would also have four lengths of 95 mm^2 cable. However, if you have one string of four turbines, you would need to size up some of the cable to 240 mm^2. You would end up with two lengths of 240 mm^2 cable and two lengths of 95 mm^2 cable. If each length is 2,582 m, the cost of the 95 mm^2 cable is $266/m and the 240 mm^2 cable is $305/m, then your cost for four strings of one or two strings of two turbines is $3,154,952, while your cost for one string of four turbines is $3,777,725. This is not an insignificant difference, but the model also considers the possibility of exporting the power from the string of four without an offshore substation, while the four strings of one turbine would require some type of combiner box or bus bar or substation in order to avoid running four cables to shore.

A.3.2 Export Cables

The export cable costs are much simpler than the array cable costs. Similar to the array cables, the relationship between size and cost is established based on academic literature (dependent on the rated voltage of the cable). It is assumed that 1 km of the export cable is a dynamic cable, with a 100% price premium. The power capacity of the cables are calculated based on Equation 1 (see above). The cost of the minimum export cable size is multiplied by the distance to landfall to calculate the total farm cost. If no cable is big enough to carry the whole load of the farm, then multiple cables will be used.

A.3.3 Offshore Substation

Offshore substations are used to connect the interarray cables with the export cable back to shore. This is not a replacement for onshore substations that connect to the electrical grid infrastructure. The number of offshore substations is assumed to be the same as the number of export cables. Each substation is assumed to be floating on a platform of a similar cost to the substructure and mooring system that support the wind turbines. The cost of the substation is based on the substation rating and its location, with a relatively small premium for offshore substations.

A.3.4 Total Electrical Infrastructure

The sum total cost of the array cables, the export cabling, the substations, and the platforms and moorings are compared to determine the lowest cost design. The lowest cost design is selected for the model, disregarding considerations of power loss or redundancy.

There are a large number of assumptions made in this component model. The first significant assumption is that cost is the main driver for design selection (costs for the 144 MW farm range from approximately $700/kW to $900/kW, so the cost can vary significantly if there is a different priority). Second, it is assumed that all the cables are 3-core cables. Third, it is assumed that the price premium for dynamic cables is 15% for cables used in the array, and 100% for export cables (the difference is due to the size of the cable and the impact on the engineering and structural integrity of the cable). Fourth, it is assumed that the array cables are either 33 or 66 kV and that for medium voltage submarine cables under 99kV, costs ($/m) are independent of voltage. Fifth, it is assumed that the turbine cables are laid out in a grid, and that they are daisy-chained together. The length of the array cable between each turbine is 9.3 times the diameter of the turbine rotor, plus the length needed to float the cable between 100-150 meters below the sea surface (adding approximately 500 meters). Finally, it is assumed that gas-insulated substations (substations that are enclosed and insulated with hexaflouride gas, allowing for a smaller footprint and for more protection from the elements) are used (*GIS | High-Voltage Gas Insulated Switchgear Substations*, n.d.).

This cost model is limited due to the following factors. First, the cost data used to determine the costs of the submarine cables is relatively old. Second, the model does not account for losses. Losses are calculated in the power production model, but cables might be sized due to losses instead of purchase price, which is not accounted for in this model. Third, there might be system accessories that are necessary but not included in the model.

The data used in this cost model includes academic literature, manufacturer publications and personal communications with experts. Dicorato, Gonzalez-Rodriguez, and Ioannou have reported their cable cost assumptions (Dicorato et al., 2011; Gonzalez-Rodriguez, 2016; Ioannou et al., 2018). ABB's catalog is used to estimate the ampacity of different cable sizes (*ABB*, n.d.).

A.4 Transmission Upgrades

The electric grid is very complex, as are transmission limits and upgrades, and therefore the associated costs. The local electric utility, Pacific Gas and Electric (PG&E), determined transmission constraints and transmission system upgrade costs for potential offshore wind farms. PG&E provided cost estimates for the upgrades required for different wind farm sizes and potential transmission pathways. Transmission scenarios recommended by PG&E are described in Table 10. A full description of the transmission upgrades are described in Pacific Gas and Electric Company (2020). The submarine pathway total cost estimate includes both the PG&E upgrade estimates and the submarine cable cost estimate provided by Mott MacDonald.

Table 10: Transmission upgrade costs

Scenario	*Cost estimate range*	*Midpoint*	*Scenario Estimate ($/kW) (corrected for COD)*	*Source*
48 MW	$363.45M - $726M	$545M	$ 11,984.05	Pacific Gas and Electric Company (2020)
144 MW	$669M - $1,340M	$1,005M	$ 7,366.40	Pacific Gas and Electric Company (2020)
1836 MW eastern path	$1,290M - $2,590M	$1,940M	$ 1,115.83	Pacific Gas and Electric Company (2020)
1836 MW southern path	$1,300M - $2,600M	$1,950M	$ 1,121.58	Pacific Gas and Electric Company (2020)
1836 MW submarine path, grid upgrades	$820M - $1,640M	$1,230M	$ 2,488.92	Pacific Gas and Electric Company (2020)
1836 MW submarine path, cable only	$2,500M – $3,500M	$3,00M	$ 11,984.05	Porter & Phillips, (2020).

The midpoints of the provided cost range are used as the transmission upgrade cost in the cost model. The costs are provided in 2019 dollars, so they are escalated to the appropriate year for transmission construction following escalation factors provided by PG&E, based on IHS Global Insight's Q3 2019 Power, summarized in Table 11.

Table 11: Escalation values adapted from PG&E project report (Pacific Gas and Electric Company (2020))

	2020	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Escalation Rates (%)	2.50	1.70	1.70	2.1	2.3	2.3	2.3	2.4	2.4	2.1	2.3
2019 Escalation Factors	1.000	1.017	1.034	1.056	1.080	1.105	1.131	1.158	1.185	1.210	1.238

A.5 Port Fees and Costs

The Port of Humboldt Bay is currently not able to support either assembly activities or operational and maintenance activities for an offshore wind farm, but is in the process of soliciting proposals for a terminal operator that would make the necessary port infrastructure upgrades development and upgrades (*Lease of Marine Terminal I*, 2019). It is expected that the terminal operator would charge various fees for use of terminal facilities by wind farm developers and operators, allowing the operator to recoup the port development costs. Costs will be different for different stakeholders. For this reason, costs are calculated differently for different parts of the economic analysis.

The costs borne directly by the wind farm developer effect economic viability of the wind farm, and are estimated based on a recent published estimate. These costs include the various fees that a terminal operator would charge for use of the terminal facilities. The estimate for port fees and costs derives from Musial et al. (2019a), as it is the most geographically comparable study in the literature, and is the most recent available published authoritative source.

Total port upgrade and development costs have been estimated by a project partner, Mott MacDonald, and depend on wind farm scale (see Porter and Phillips, 2020). The upgrades required by a small wind farm would cost between 130-200 million dollars (midpoint at 165 million dollars, 2019 vintage) while the upgrades required for a large farm would be between 400-700 million dollars (midpoint at 575 million dollars). Similar to the transmission cost estimates, the midpoint is taken as the cost estimate for the model. The economic impact assessment utilizes these costs to determine the impact of the development of a wind farm on the local economy.

A.6 Installation

The installation and assembly cost model is a bottom-up model, validated against expert estimates, and includes cost reductions attributed to learning effects. The major part of the cost model is based on installation and assembly actions, the expected time for each action (adjusted for the operational weather window (OWW)), the personnel and vessels required for each action, and wages and vessel day rates, see equations 2, 3, and 4:

Equation 2: Total cost (for activity A) = Personnel cost + Vessel cost

Equation 3: Personnel cost = Time (hours, adjusted for OWW) * Number of personnel * Wage ($/hr)

Equation 4: Vessel cost = Time (days, adjusted for OWW, rounded up) * Vessel day rate ($/day)

Actions are based on the required actions for the installation and assembly for each part of the farm, see Table 12. The OWW is assumed to be 30% for every activity that includes vessels at sea. Wages have an overhead of 37.6% added to the personnel costs.

Table 12: Installation action assumptions

Action	*Time*	*Units*
Port to site and return (export cable lay)	4	hours (total)
Export cable pre-lay & post lay	3	hours (total)
Export cable lay and trench	44	hours (total)
Array cable import		
Port to site and return (array cable lay)	7	hours/trip (1 trip per 5,000 tonnes, approx. 70 km of cable)
Array cable lay	6	hours/turbine
HDD drill & pull cable	7	months
Port to site and return (mooring system lay)	4	hours/ 6 anchors
Mooring system drop & buoy off	6	hours/anchor
Turbine component imports	n/a	see total cost
Turbine assembly	1	days/turbine
Turbine pre-commissioning	4	hours/turbine
Turbine tow out	10	hours/turbine
Turbine ballast	12	hours/turbine
Turbine attach	10	hours/turbine
Turbine commissioning	18	hours/turbine
Return to port (turbine tow out)	2	hours/turbine
Substructure import	20	days/3 turbines
Substructure offloading	12	hours/turbine
Substructure pre-testing	6	hours/turbine

There are a number of assumptions that go into this model. The first, most important set of assumptions are regarding the timing of different actions. Action timing (in hours and days) was estimated based on a combination of academic literature, developer videos, and personal communications. In addition, 30% of the time was added to every action at sea to account for the possibility of waiting for better weather. It is assumed that installation activities are scheduled for the summer, which is generally calmer weather in northern California, but it is still likely that there will be some conditions that are not appropriate for installation activities. Secondly, it is assumed that vessel day rates include crew, and that the crew is capable of performing vessel-specific actions (for example, the crew of the anchor handling tug supply vessel are assumed to be responsible for dropping the anchors and setting up the mooring systems in-situ). Third, it is assumed that substructure assembly costs are included in the line-item for the cost of the substructure, so the installation line item for the cost of the substructure does not increase if the substructure is assembled locally.

This cost model accounts for all installation processes and builds the cost from the bottom up. There are a few improvements that could be made to improve the accuracy, but which were outside the scope of this work. First, the timing of the different activities is not well validated. Second, the model does not consider scheduling - it is assumed that every action can happen when it needs to without interfering with other installation activities. Third, the operational weather window (OWW) is an industry standard method, but it is simplified to 30% of time for every activity and does not account for northern California specific conditions or vessel specific limits.

The data that is utilized in this model includes academic literature, industry reports, and video evidence. Data regarding the timing of different actions is drawn from videos and from the NREL cost model documentation (Maness et al., 2017; Beiter et al., 2016). Wage data is drawn from literature regarding the offshore wind industry in northern California (Collins & Daoud, 2019). Vessel data, including day rates, speeds, and vessel capacity, is drawn from maritime industry reports and from academic literature regarding offshore wind vessels.

A.7 Development

Development costs were estimated based on simple estimates for a number of sub-components. Development costs include engineering and management, permitting, and site characterization. These costs are calculated for 2019, then reduced to account for the learning effect. Engineering & management is estimated to be 4% of balance of systems and turbine costs (Beiter et al., 2016). Permitting and site characterization costs are estimated to be a flat value (approximately 13 million dollars and 4 million dollars respectively) due to lack of information regarding potential scale effects on permitting costs (Maness et al., 2017).

Assumptions for this model are costs reported from the NREL balance of system (BOS) model in 2016 (Maness et al., 2017). The assumption that permitting and site characterizations costs are flat is an assumption that likely over-estimates cost for smaller farms and under-estimates costs for larger farms.

A.8 Soft Costs

In this cost model, soft costs include construction financing, construction insurance, commissioning, a decommissioning bond, procurement contingencies, installation contingencies, and the initial lease costs. Most of these costs are estimated using cost factors, see Table 13. Construction financing costs were estimated using an industry expert estimate (Musial et al., 2019a). The lease cost was estimated as a simple average of previous BOEM lease costs due to the deep uncertainty of auction-based costs and the nascent stage of the floating technology.

Table 13: Cost factors for estimating soft costs

Component	*Value*	*Applied to*	*Source*
Construction Insurance	1%	Turbine and BOS	Beiter (2016)
Insurance (general)	1%	Turbine and BOS	Beiter (2016)
Decommissioning Bond	15%	Turbine and BOS	Beiter (2016)
Procurement Contingency	5%	Hardware	Beiter (2016)
Installation Contingency	30%	Installation	Beiter (2016)
Commissioning	1%	Turbine and BOS	Beiter (2016)

A.9 Operations

Operational costs are calculated as the sum of the costs of sub-components. Operations costs include the BOEM lease fee, insurance, administration and management, port costs and fees, and grid costs and fees. The BOEM operating fee is calculated based on BOEM documentation, see equation 5. Insurance costs are estimated based on Castro-Santos et al. (2016). Administration and management costs are based on a previous version of an NREL cost model, in the back end of the Jobs and Economic Development Impact model and both port and grid costs and fees are assumed to be nearly zero (National Renewable Energy Laboratory, 2019).

Equation 5: Operating fee = (Op fee rate, %)*(nameplate, MW)*(cap factor, %)*(hrs per year)*(average LMP)

where,
Op fee rate = 2%
hours per year = 8760
Average LMP is assumed to be $40/MWh

There are a number of simplifying assumptions that are included in this cost estimate. It is assumed that operational insurance as well as management and administration costs are simple costs in $/kW that do not change with farm scale due to lack of granularity in industry estimates. In addition, port fees and costs are neglected due to high levels of uncertainty and the lack of local infrastructure - the development of the O&M port will define the port costs and fees. Ongoing grid connection fees do not seem to be significant for generators' operations, although there are relatively small fees for the initial connection (CAISO, 2013).

Sources of data for the estimation of operational costs are based on government documentation and academic literature. BOEM has documented the fees associated with leasing (Bureau of Ocean Energy Management, 2018).The academic literature is used to estimate insurance and administration costs and management costs (Castro-Santos et al., 2016; Maness et al., 2017; Beiter et al., 2016).

A.10 Maintenance

The cost model for maintenance costs are based on a bottom-up model. Maintenance costs are separated into three types of maintenance: calendar maintenance, condition-based maintenance, and corrective maintenance (Ioannou et al., 2018). Corrective maintenance costs are calculated for three types of turbine failures: minor repairs, major repairs, and major replacements, and cable repairs, see equation 6. Note that the model does not include any maintenance costs for hardware once the power has reached the state-wide grid.

> Equation 6: Maintenance cost (for failure A)=(failure rate)*[material costs + (vessel rate)*(repair time+travel time+mobilization time)+ (wages)*(number of technicians)*(repair time+travel time)]

Condition based maintenance is calculated as 20% of corrective maintenance. Calendar based maintenance is estimated similarly to the corrective maintenance (see equation 6) for an in-situ annual maintenance and a larger, quayside maintenance occurring every five years. Material costs are assumed to be double the average minor or major repair cost for annual and five-year maintenance, respectively. Repair duration is assumed to be 12 or 36 hours for annual and five-year maintenance, respectively.

The assumptions built into the maintenance cost estimate are as follows: First, it assumes that failure rates are constant for the life of the project and do not vary with the severity of the weather regime or the frequency of proactive maintenance activities. Second, scheduling issues are not included in the calculations - it is assumed that technicians and vessels are available when needed. Third, it is assumed that the failure rate for the mooring lines is zero. Fourth, it is assumed that the time required to wait for an operable weather window (OWW) is 30%.

In addition to the assumptions, there are a number of limitations for this simplified cost model. First, the effect of the local weather regime might be underestimated. Dewan et al. (2016) notes that weather in Northern California is more extreme than in the North Sea, so failure rates might be higher than the majority of global installed capacity. Second, the relationship between failure rate and turbine size is not included because it is unknown. In addition, the material cost estimates to complete the repairs are for smaller turbines, but the relationship between cost and turbine size is unknown.

Input data for the model comes primarily from the academic literature. The method is drawn from Ioannou (2018) and NREL adjustments to the Research Institute of the Netherlands O&M tool (Beiter et al., 2016). Failure rates, material costs, and number of technicians come from a summary table published by Ioannou (2018). Wage data is drawn from literature regarding the offshore wind industry in Northern California (Collins & Daoud, 2019). Vessel data (including day rates, speeds, and vessel capacity) is drawn from maritime industry reports and from academic literature regarding offshore wind vessels (Dalgic et al., n.d.; "Anchor Handling Tug (AHT) Orcus," n.d.; Paterson et al., 2017; Burgess, 2016;

Lacal-Arantegui et al., 2018). Cable failure rates are drawn from construction development reports for HVDC submarine cable projects (European Regional Development Fund, n.d.).