The Cost of Offshore Wind Energy in the United States From 2025 to 2050

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National Renewable Energy Laboratory

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List of Acronyms

BOEM	Bureau of Ocean Energy Management
CapEx	capital expenditures
COD	commercial operation date
FCR	fixed charge rate
FLORIS	FLOw Redirection and Induction in Steady State
FORCE	Forecasting Offshore Wind Reductions in Cost of Energy
GW	gigawatt
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
ITC	investment tax credit
km	kilometer
kW	kilowatt
LCOE	levelized cost of energy
m	meter
m^2	square meter
MW	megawatt
NCF	net capacity factor
NREL	National Renewable Energy Laboratory
NRWAL	National Renewable Energy Laboratory Wind Analysis Library
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OpEx	operational expenditures
ORBIT	Offshore Renewables Balance of System and Installation Tool
OREC	offshore renewable energy certificate
POI	point(s) of interconnection
reV	Renewable Energy Potential model
SOFR	secured overnight financing rate
USD	U.S. dollar(s)
W	watt
WACC	weighted average cost of capital
WOMBAT	Windfarm Operations and Maintenance cost-Benefit Analysis Tool

Executive Summary

Offshore wind energy has the potential to play a significant role in mitigating the worst effects of climate change. Decision makers in coastal regions that are planning for or considering offshore wind deployment need reliable technology, cost, and performance data to understand the role that offshore wind energy can play in their future clean energy strategies. The National Renewable Energy Laboratory (NREL) was commissioned by the Bureau of Ocean Energy Management (BOEM) to assess how our current understanding of wind resource, technology choices, and infrastructure development could impact the evolution of offshore wind energy costs throughout the United States. The results presented in this report could be used to inform marine spatial planning, state renewable portfolio standards development, federal research and development programs, or other engagement with offshore wind energy stakeholders.

Background

The offshore wind energy industry is at a critical juncture in the United States. Project developers have reported significant cost increases since 2021 due to the rising cost of capital, higher commodity prices, and supply chain constraints. Figure ES-1 underscores the impact of these factors on offshore renewable energy certificate (OREC) strike prices[1] for four New York offshore wind projects. The figure compares the original strike prices of the four projects (grey bars in the figure) with price adjustments recently requested by developers to provide relief from broader economic challenges (top of the bars in the figure). The requested price adjustments represent increases of 27%—65%, with a weighted average price increase of nearly 50% from 2021 through 2023.

[1] The strike price is the dollar value at which a power utility or state regulator such as the New York State Energy Research and Development Authority agrees to purchase an OREC representing the environmental benefits associated with one megawatt-hour of electricity generated from a specific offshore wind project.

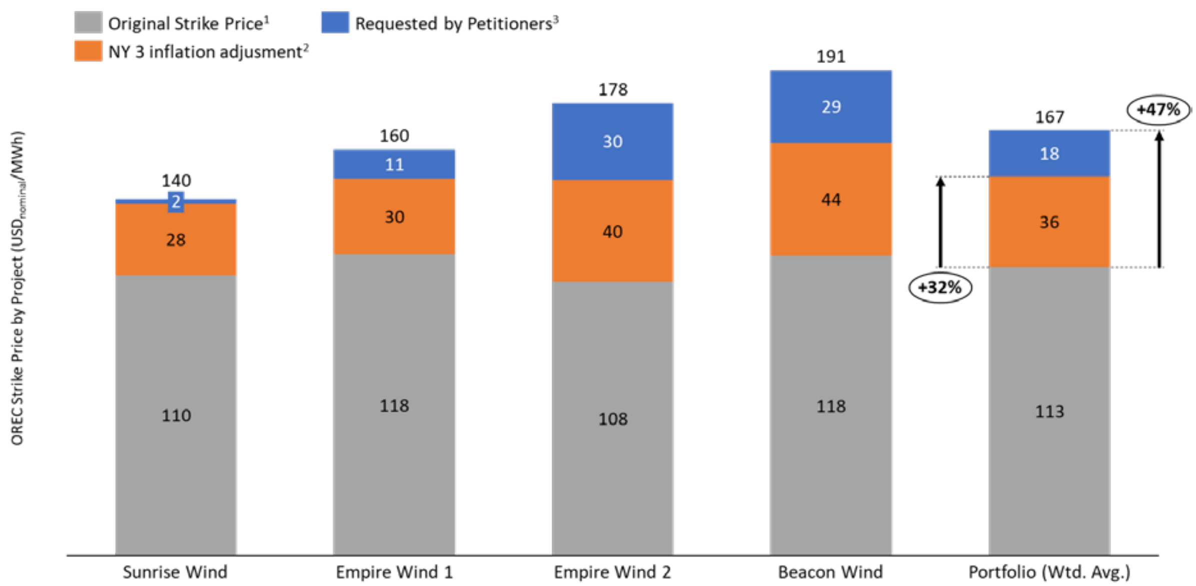

Figure ES-1. Petitioned price adjustments for four New York projects

Notes: 1) The original OREC strike price agreed upon in solicitation ORECRFP18-1 (NY1) and solicitation ORECRFP20-1 (NY2); 2) the OREC strike price based on NY3 inflation adjustment based on commodity indices for labor, fabrication, steel, diesel, and copper as of June 2023; 3) requested OREC price by offshore wind petitioners (i.e., Sunrise Wind, Empire Wind 1, Empire Wind 2, and Beacon Wind). Note that the petitioned price levels may reflect investment tax credit election by the petitioners. A direct comparison to levelized cost of energy should factor in several differences between offtake prices and the levelized cost of energy (Beiter et al. 2021).

Despite these economic difficulties, the industry has also made significant advances over the same time frame. Since 2021, the first commercial U.S. projects (South Fork Wind and Vineyard Wind I) began delivering power to the electric grid and there has been substantial progress in offtake agreements, federal permitting approvals, and expanded leasing plans. It is important for the offshore wind sector to understand both near- and longer-term impacts of cost pressures to continue strategically developing the industry with the momentum these activities have generated.

This study presents estimates of the levelized cost of energy (LCOE) of offshore wind energy throughout major U.S. coastal regions between 2025 and 2050. The LCOE modeling accounts for impacts of supply chain shocks, inflation, and rising interest rates on cost. Given the near-term uncertainty in these factors, we present three possible scenarios driven by how uncertainty in costs, technology, and deployment may evolve over time. The cost increases reported by industry in recent years will likely be felt over the next several years, but we expect long-term cost reductions enabled by growing offshore wind deployment and industry learning.

Levelized Cost of Energy and Modeling Approach

LCOE represents the average unit cost of energy over an electricity plant’s lifetime. It provides useful initial insight into electricity generation resource costs and competitiveness, but it does not account for everything required to determine the optimal or best value option for the grid at a specific place and time. Care must be taken when comparing LCOE estimates across technologies or with electricity prices to account for various revenue streams, subsidy schemes, electric transmission system upgrade costs, and other benefits. We present unsubsidized LCOE values in this report at the point of grid interconnection. The LCOE values presented in this report are intended to capture broad spatial and temporal scales and not to model specific project costs.

To update offshore wind LCOE in the United States, we incorporate the best-available wind resource assessments, infrastructure data, and technology trends into NREL's bottom-up models to calculate base year costs. We then derive offshore wind energy project cost trajectories in two parts: long-term cost projections based on global industry experience and near-term corrections to represent the cost impacts of supply chain disruptions, inflation, and rising interest rates. We apply multiple scenarios to account for different rates of industry growth and persistence of current economic challenges so that decision makers can understand the potential range of future LCOE values. The spatial variation of LCOE throughout the country is shown in maps such as Figure ES-2 for different times between 2025 and 2050.

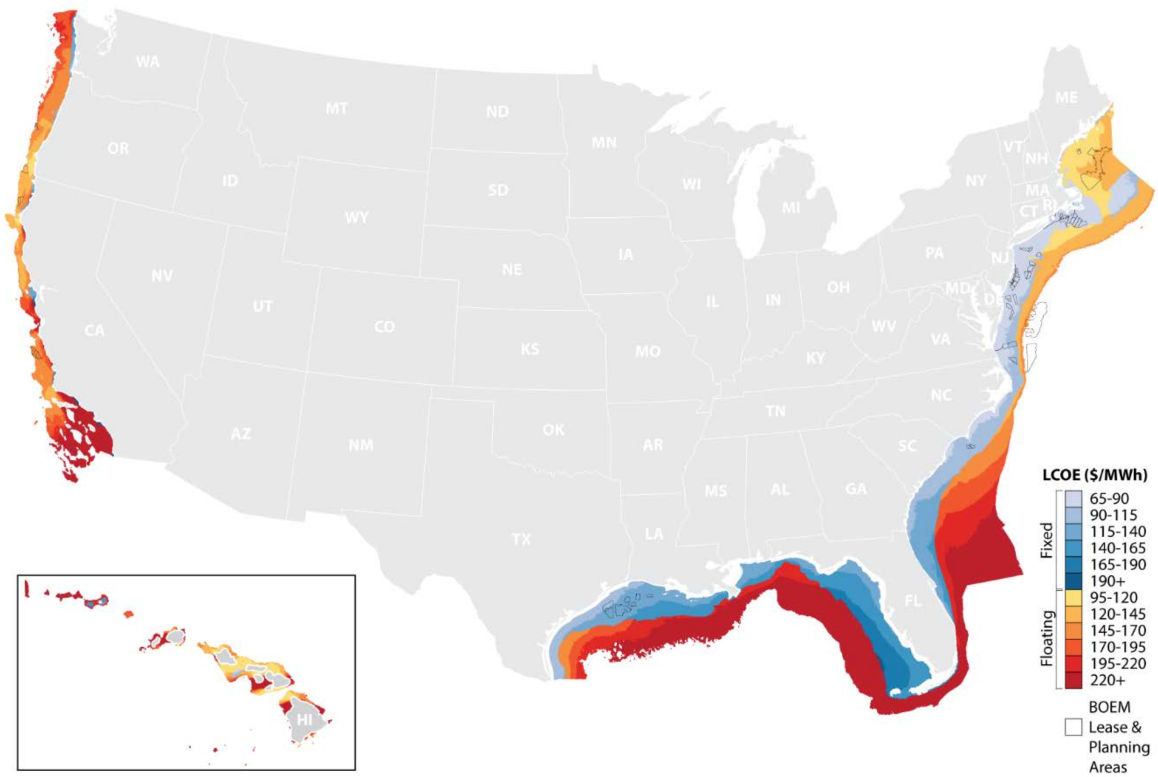

Figure ES-2. National LCOE ($/megawatt-hour [MWh]) for 2035 in 2022 U.S. dollars. ***Figure from Gabriel R. Zuckerman, NREL***

Key Takeaways

The key takeaways of this study include the following:

- Economic challenges and supply chain disruptions have led to reported offshore wind project cost increases of around 50% since the end of 2020; however, at the same time, there has been significant progress in offtake agreements, federal permitting approvals, and expanded leasing plans. As a result, it is important to understand how near-term cost pressures could impact future cost trends throughout the United States to help inform the ongoing advancement of offshore wind energy development.

- The near-term trends in inflation, interest rates, and supply chain bottlenecks are highly uncertain. As a result, we define multiple near-term cost scenarios coupled with long-term learning curves to reflect the range of potential future values of the LCOE. These scenarios are illustrated in Figure ES-3. These cost trajectories report higher costs than previous NREL studies to account for recent economic challenges, changes in the deployment pipeline, and a methodological update to represent floating wind's transition into a mature industry rather than assuming availability of mature supply chains from the first project.
- We estimate the LCOE of a reference fixed-bottom project on the East Coast to be around $129/megawatt-hour (MWh) for commercial operation dates in 2025 in the mid scenario. The conservative and advanced scenarios indicate that the range of costs could be 28% higher or 20% lower than this value. We estimate that, under the mid scenario, these costs could decrease by around 39% (to $79/MWh) by 2035 and 45% (to $72/MWh) by 2050 as the maturing industry derives diminishing returns from the learning curve. In the conservative and advanced scenarios, we could see cost reductions in 2050 of around 30% to 56% relative LCOE.
- We estimate the LCOE of floating projects at a reference West Coast site to be around $198/MWh for commercial operation dates in 2030 in the mid scenario[2]. The conservative and advanced scenarios indicate that the range of costs in 2030 could be around 58% higher or 32% lower than this value. We estimate that costs, under the mid scenario, could decrease by around 31% by 2035 (to $136/MWh) and 52% by 2050 (to $95/MWh) as the industry matures and growing deployment enables industry learning. Under the conservative and advanced scenarios in 2050, we could see cost decreases of 25% to 69% relative to the 2030 mid scenario LCOE, respectively. By 2036, our floating reference site's LCOE drops below the 2025 fixed-bottom reference site in the mid scenario, whereas some floating sites in the North and Central Atlantic, West Coast, and Hawai`i drop below $100/MWh in the mid scenario.
- Offshore wind costs also demonstrate significant spatial variation because of differences in water depth, wind resource, and distance to key infrastructure; for example, in 2035, mid-case LCOE for fixed-bottom projects is roughly 18% higher for sites in the South Atlantic region relative to those in the North Atlantic. Across all sites, a Central Atlantic fixed-bottom project LCOE is similar to that of a North Atlantic fixed-bottom project. In general, fixed-bottom LCOE in the Gulf of Mexico is 60%−70% higher than the LCOE in Central and North Atlantic fixed-bottom sites. We estimate that the LCOE for floating wind projects in regions currently being considered or developed (Central and Northern California and the Gulf of Maine) are some of the lowest in the country.[3]

[2] We report floating wind project costs for years starting in 2030 because it is unlikely that the permitting approvals and infrastructure development could be completed earlier.
[3] A complete set of cost results between 2025 and 2050 over the entire spatial domain are available via an online, interactive map at https://bit.ly/oswlcoe.

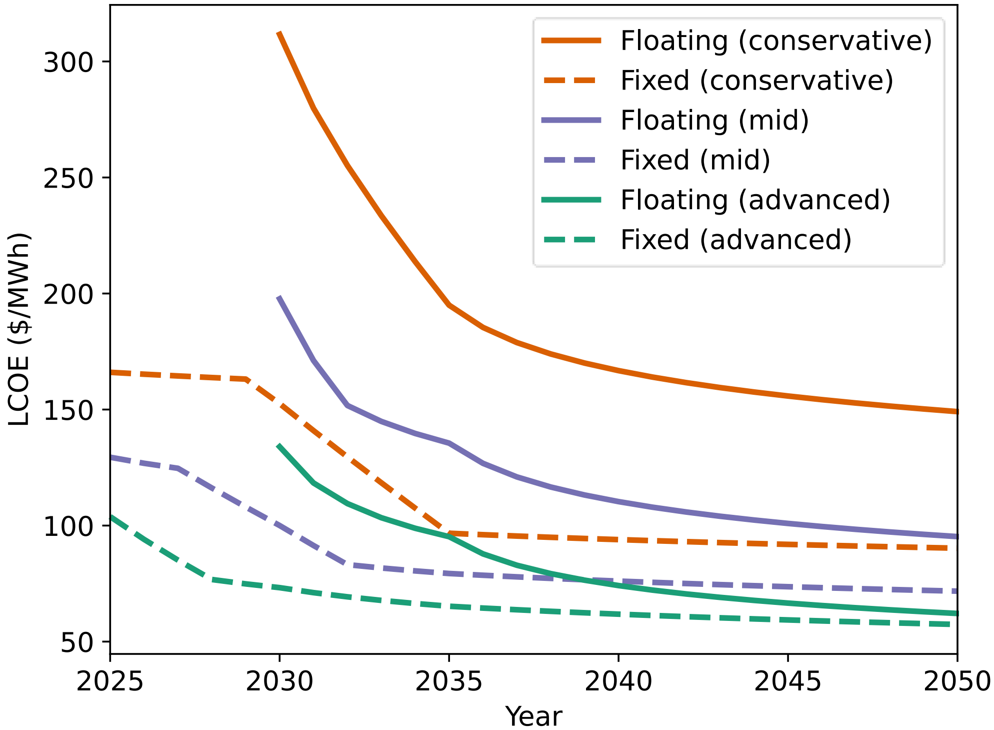

Figure ES-3. LCOE ($/MWh) for reference fixed-bottom and floating offshore wind projects.

Note: LCOE values are calculated at the point of interconnection.

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1 Introduction

The offshore wind energy market potential in the United States has grown considerably in recent years. More than 80 gigawatts (GW) of capacity are currently in the regulatory pipeline with state procurement goals exceeding 115 GW (McCoy et al. forthcoming). The first two commercial-scale projects in the United States—Vineyard Wind 1 and South Fork Wind—delivered first power near the end of 2023, marking the beginning of the operational phase of a commercial offshore wind energy buildout that is planned by the northeast states (Musial et al. 2023b). New York has recently had a fourth-round solicitation that returned 1.7 GW of capacity to the state (Ferry (2024), Section 7.5.1). Lessons learned from the first wave of offshore wind project development can inform the location, timing, and process for deployment in subsequent phases. The existing pipeline could conceivably be deployed by the mid-2030s (Bloomberg New Energy Finance 2022; 4C Offshore 2023a) and additional leasing will be necessary to achieve state and national targets.

This report was funded by the Bureau of Ocean Energy Management (BOEM) under an interagency agreement with the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). Offshore wind energy cost estimates vary considerably across the United States. Therefore, gaining an understanding of how costs differ from one site to another can help determine the economic suitability of areas for state and federal energy planning, leasing, and project development. Wind speed, distance to ports and interconnection, water depth, and other parameters are geospatial variables that impact the site-specific cost of offshore wind energy. By combining these spatial features with wind turbine size (e.g., nameplate rating and rotor diameter), substructure type, performance, siting density, operational strategies, and deployment timing, we can estimate the overall life cycle costs for representative projects in waters off the Atlantic Coast, Pacific Coast, Gulf of Mexico, and Hawai`i.

During the past 2 years, the offshore wind energy sector has encountered major economic challenges from a dynamic cost environment. For example, cost trends in Europe have suggested a decrease in the levelized cost of energy (LCOE)[4] of around 50% between 2014 and 2021 (Musial et al. 2023b). Since 2021, a combination of "rampant inflation, global supply chain disruptions, and soaring interest rates" (Public Service Commission of the State of New York, 2023) have reversed this trajectory for both European and American offshore wind energy project costs. As a result, 10.7 GW) of U.S. offtake contracts have already been terminated,[5] and 4.2 GW of capacity that is subject to rejected price adjustment petitions from state regulatory authorities (Public Service Commission of the State of New York 2023; Nasralla and Bousso 2023). State energy agencies appear to be recalibrating their strategies for offshore wind energy procurement to account for these recent macroeconomic[6] market disruptions (e.g., by including labor and commodity price escalators in offtake contracts). In response to these macroeconomic and inflationary challenges, New York State issued a new procurement round in 2023 and two of

[4] The levelized cost of energy is the annualized cost to finance, construct, and operate a power plant scaled by the annual energy production. It is a summary metric that is useful for comparing the costs of different generation technologies, or for considering how the evolution of capital expenditures, operational expenditures, or capacity factor could impact future costs.
[5] Offtake contracts have already been terminated or contract holders are reportedly seeking termination.
[6] Macroeconomic impacts relate to the behavior of the national (or, arguably, international) economy and may include inflation, federal interest rates, or commodity prices.

the cancelled projects successfully rebid (1.7 GW) (New York State Energy Research and Development Authority [NYSERDA] 2024a). Still, some of the uncertainty created by these disruptions might affect deployment schedules, domestic supply chain buildout, and public acceptance.

In this environment, it is challenging to estimate the costs of offshore wind because during the drafting of this report, costs have simultaneously been reassessed across the sector and validation data are sparse. Some insights into the scale of cost increases over the past 2 years can be inferred from the public filings provided by offtake contract holders. Federal policy incentives that mitigate the negative impacts of the recent economic challenges, such as the Inflation Reduction Act, have just begun to take effect. However, the extent to which the various investment tax credit[7] (ITC) provisions (including bonus credits) can be elected by U.S. offshore wind developers is still somewhat unclear.

A spatial-economic cost reduction pathway analysis for offshore wind energy throughout major U.S. coastal areas was introduced in 2016 (Beiter et al. 2016). The authors developed a modeling framework to estimate spatially-dependent costs and the economic viability of offshore wind, and considered how costs could evolve between 2015 and 2030. This modeling framework was subsequently used for more detailed regional studies in Maine, Oregon, California, and Hawaii (Musial et al. 2019, 2020; Beiter et al. 2020; Shields et al. 2021b), annual cost and market updates (e.g., Musial et al. 2023b), and follow-on analyses into economic potential and cost sensitivities (Beiter et al. 2017; Shields, Beiter, and Kleiber 2021).

In this report, we present costs for fixed-bottom and floating offshore wind technologies across major U.S. coastal areas between 2025 and 2050. The modeling framework evolved from the many NREL studies conducted since the original report by Beiter et al. (2016) and reflects our improved understanding of the following:

- Emerging port, interconnection, and manufacturing locations
- Future cost trajectories based on historical empirical data from the growing global pipeline
- Component and installation costs that have changed over the past few years because of global supply chain constraints and higher commodity prices
- Technology choices that have become clearer as U.S. projects advance toward commercial operation.

This assessment is timely because offshore wind economics have changed considerably over the past few years, which could impact the strategic planning for the next phase of offshore wind energy development in the United States. As such, we recognize that there is both increased uncertainty and urgency to obtain cost data. We therefore present ranges of costs that reflect that uncertainty in current costs and the long-term evolution of the offshore wind sector.

[7] The investment tax credit is a one-time federal income tax credit for capital investments in renewable energy projects based on the dollar value of the investment.

The report is organized as follows. First, we introduce the motivation for a long-term cost analysis and study scope (Section 2). In Sections 3 and 4, we outline technology assumptions and methods for calculating annual energy production. Potential available infrastructure, such as points of interconnection (POI), ports, and vessels are also used as inputs into our cost modeling and are discussed in Section 5. Section 6 includes an outline of our cost modeling approach, which uses the previously described inputs as well as the description of cost components and assumptions for developing final cost projections. Cost projections are provided in Section 7, and a summary with conclusions and caveats are given in Sections 8 and 9, respectively.

2 The Motivation for a Long-Term Cost Analysis for Offshore Wind Energy in the United States

2.1 The Current Cost Environment

Offshore wind energy costs have been subject to considerable increases between 2021 and 2023. Among lease holders with offtake contracts[8] established between 2019 and 2022 along the Atlantic Coast (Musial 2023b), 12 have terminated their contract (10.7 GW)[9] and four of these projects had price adjustment petition rejected by state regulatory authorities (4.2 GW) (Public Service Commission of the State of New York 2023; Nasralla and Bousso 2023). Two of these projects successfully rebid into a new procurement round issued in 2023 in response to macroeconomic and inflationary challenges (1.7 GW) (NYSERDA 2024a). Vessel delays were a major contributor to determining that the projects were not viable. At higher costs, the offtake prices established several months to multiple years prior no longer match current costs. It appears that higher costs incurred by projects with anticipated starts of commercial operation in the mid- to late-2020s are widespread across U.S. and European projects (Ørsted 2023).

U.S. contract holders suggest a combination of "rampant inflation, global supply chain disruptions, and soaring interest rates" (Public Service Commission of the State of New York 2023) has impaired their ability to meet offtake contract obligations. In a recent regulatory filing, offtake contract holders in New York have proposed contract price adjustments that would suggest a 50% increase on average between the dates the contracts were awarded (2018 – 2020) and the date of the filing (2023) (Public Service Commission of the State of New York 2023).[10] Vattenfall, one of the largest offshore wind operators in the world has reported price increases up to 40% for the offshore wind energy sector (Vattenfall 2023). This aligns with recent survey data of industry participants that suggest cost increases between 11% and 20% since 2021, with a smaller number of respondents indicating increases of more than 30% (Westwood Global Energy Group 2023).[11] Higher offshore wind generation costs from commodity prices and supply chain bottlenecks observed today could return to longer-term average levels soon, but they might also persist at their current levels or increase further.[12] We estimate that a combination of increases in the cost of capital, commodity prices, and supply chain constraints have resulted in an increase in LCOE of nearly 50% between 2020 and 2023 (see Section 6.2 for a more detailed breakdown).

[8] An offtake contract is an agreement where a project developer agrees to sell electricity from an offshore wind project, or offshore renewable energy certificates representing the amount of energy generation from that offshore wind project, to a state regulatory authority such as an electric utility.

[9] This estimate counts separate phases of development within one lease area as individual projects (e.g., Empire Wind 1 and Empire Wind 2 are two distinct projects).

[10] The capacity-weighted average of the offshore renewable energy certificate price adjustment between the projects Empire Wind 1, Empire Wind 2, Beacon Wind 1, and Sunrise Wind. The offshore renewable energy certificate award dates were in 2018 for Empire Wind 1 and Sunrise Wind; and 2020 for Empire Wind 2 and Beacon Wind 1.

[11] The survey refers broadly to "cost inflation" without specifying the cost component(s) these responses refer to (e.g., LCOE or capital costs).

[12] We do not account for further increases reported in insurance costs because they constitute a relatively small portion of LCOE.

2.2 Estimating Future Offshore Wind Costs Under Different Scenarios

The cost increases from 2020 to 2023 have created challenges for the offshore wind energy sector and led to some questions about how the industry will progress. Yet, there has been clear interest from federal and state governments and industry practitioners to continue planning and expanding the development of offshore wind energy in the United States. Specifically, since the beginning of 2023 the United States has:

- Delivered first power to the grid from the first two commercial-scale projects (Vineyard Wind 2024; South Fork Wind n.d.)
- Expanded and coordinated procurement activity (State of Massachusetts 2023; NYSERDA 2024a)
- Seen significant private investment in critical path supply chain investments (Nucor 2023)
- Integrated offshore wind energy needs into transmission planning (California Independent System Operator 2024)
- Awarded substantial federal grants for offshore wind infrastructure (Office of Alex Padilla 2024)
- Received federal approval of over 10 GW of offshore wind energy projects (U.S. Department of the Interior 2024)
- Announced a new five-year schedule for offshore wind leasing in the Gulf of Mexico, the Central Atlantic, the New York Bight, California, the Gulf of Maine, U.S. territories, and Hawai`i (BOEM 2024).

Despite these promising developments and the potential for offshore wind to generate additional value streams such as creating U.S. jobs and revitalizing coastal communities (Shields et al. 2023a), cost remains one of the primary drivers of project viability. As a result, it is important for stakeholders and decision makers to have an up-to-date understanding of offshore wind cost trajectories throughout the United States along with an appreciation for how different industry-specific and broader economic scenarios could affect the range of cost outcomes. This report aims to provide information that both reflects the short-term economic challenges facing the industry as well as long-term growth trajectories under a range of cost, economic, and deployment scenarios. The range of reported outcomes can help decision makers plan for different outcomes; furthermore, we provide the results in a publicly accessible interactive map so that readers can explore costs that are relevant to their own spatial and temporal needs.

The costs presented in this report are typically higher than those from previous NREL reports (Musial et al. 2019, 2020, 2023b; Beiter et al. 2020; Shields et al. 2021b). There are two primary factors that contribute to this. First, we have adjusted near-term costs to better align with the economic and supply chain challenges facing the industry. This correction increases the costs in the early years of the long-term trajectory. Second, we adapted the methodology for floating wind cost projections to capture the transition from a nascent industry with precommercial projects to a mature industry deploying many commercial-scale projects (previous NREL studies reported costs under the assumption that a mature supply chain was available at the beginning of the time period). This change in methodology indicates higher potential costs for floating wind projects in the early 2030s as the industry matures, with costs returning to the range of previous estimates for a mature industry by the late 2030s or early 2040s. The increased short-term costs are consistent with year-on-year projections from other analyst groups (Jain, Jean-Michel, and Metcalfe 2023; Wood Mackenzie 2022a).

Because of the uncertainty in both present-day and future costs for offshore wind energy, we present multiple cost trajectories that demonstrate a potential range in future costs. We discuss the macroeconomic, supply chain, and deployment factors that could drive these future scenarios, and present a range of results both spatially and temporally. We recommend considering not only the overall magnitude of the reported costs, but also the relative trends and underlying industry drivers that could impact the future trajectory of offshore wind costs.

2.3 Study Scope

2.3.1 Spatial and Temporal Domains

In this study, we considered a spatial domain that extends from the state-federal jurisdictional boundary to the Exclusive Economic Zone boundary of all major U.S. coastal regions, except for Alaska, the Great Lakes, and U.S. territories. The assumed wind energy power plant size is 1 GW and the water depths are between 5 and 1,300 meters (m). We assume that in areas shallower than a 60-m water depth, fixed-bottom foundations are more economically viable than floating substructures. In areas deeper than 60 m, floating foundations become more feasible. This delineation could change as technologies, commodity prices, and the regulatory environment evolve in the future.

In addition, we evaluated the years 2025 through 2050 and chose this time span because many decarbonization and capacity expansion models are used for analysis to the year 2050 (Kerry and McCarthy 2021; Gagnon et al. 2023; Larson et al. 2020) and could use the results of this report as potential inputs. Furthermore, federal decarbonization targets, like the current White House goal of a net-zero-emissions economy, are aimed for 2050 (The White House 2021). The Annual Technology Baseline projects also extend through 2050 (NREL 2023).

2.3.2 Capturing Regional Considerations for Offshore Wind Energy Development

Regional site characteristics, such as hurricane activity in the Gulf of Mexico, impact the cost of wind energy. The wind resource also varies by region, which impacts the LCOE of any deployed wind plants. Therefore, when modelling the cost of wind energy on a national scale, regional considerations must be considered. As a result, we used regional wind resource datasets (Section 4.1) to evaluate the annual energy production for each region.

2.3.3 Aspects Beyond the Scope of This Study

This study does not include stakeholder or environmental considerations, a detailed supply chain assessment, or the effects of climate change on the wind resource. It also does not include any potential costs associated with upgrading ports or POIs that may be required for deploying offshore wind power plants. The costs estimated in this report do not consider any direct project subsidies, such as any benefits from the investment tax credit (ITC) or ITC bonus credits, including any impacts of the ITC on project financing structures (Section 6.5). Costs also do not include regional variation in labor rates. There is significant uncertainty in these areas and our key objective in this study is to understand relative trade-offs in costs between different regions. Some consequences of not including detailed environmental considerations could be that start dates are optimistically projected because including these considerations, while important, could further delay offshore wind energy build-out. Future research into the impact of supply chain development and environmental/stakeholder considerations on LCOE could help understand how these factors affect offshore wind energy deployment.

LCOE represents the average unit cost of energy over an electricity project's lifetime. It provides useful initial insight into electricity generation resource costs and competitiveness, but it does not account for everything required to determine the optimal or best value option for the grid at a specific place and time (NREL 2023). Care must be taken when comparing LCOE estimates across technologies or with electricity prices to account for various revenue streams, subsidy schemes, electric transmission system upgrade costs, and other benefits (Beiter et al. 2021). We present unsubsidized LCOE values in this report at the point of electricity grid interconnection.

3 Technology Assumptions

3.1 Wind Turbine

Offshore wind turbine technology is evolving rapidly (Musial et al. 2023b). Turbine original equipment manufacturers currently have offshore wind turbine prototypes with nameplate capacities in the range of 14 to 16 megawatts (MW) (Siemens Gamesa Renewable Energy 2023; Durakovic 2023; Mingyang Smart Energy 2023; Buljan 2023). GE Vernova has recently abandoned plans to make a large 18-MW wind turbine to focus on producing the backlog of the smaller Halide-X 13- and 15.5-MW turbines (Lewis 2024). Wind turbine development cycles have typically taken approximately 6–8 years from prototype to first commercial application (Musial et al. 2023b).

In 2025, we assumed a 12-MW turbine with a rotor diameter of 216 m, hub height of 137 m, and specific power of 327 watts (W)/square meter (m^2). Increases in net capacity factor (NCF) from advancements in technology are incorporated into the learning curve (Section 4.4, Figure 1).

3.1.1 Wind Turbine Pricing

While we consider this generalized upsizing in wind turbine rating to represent a likely trajectory based on industry trends, we highlight that this is only one of several possible pathways. First, we expect that several different turbine designs might be installed to account for varying seabed, logistical, and performance considerations. Second, the costs associated with continued turbine upsizing might increasingly compete with the related benefits. For example, as wind turbine size increases, the expenses to prepare the associated port and manufacturing infrastructure also increase. In contrast, one benefit of turbine upsizing is a lower required number of turbines needed to reach the desired plant capacity. However, the increasing costs associated with turbine upsizing are important to consider in terms of diminishing returns on continuous upsizing (Section 3.1.2).

Capital expenditures (CapEx) and operational expenditures (OpEx) vary by wind turbine size. This is because CapEx and OpEx change with the number of turbines to both install and maintain. With larger and higher-rated turbines, fewer turbines need to be installed and maintained for the same plant size. Capacity factors generally increase with higher turbine rating because of the greater hub heights associated with larger wind turbine models. For decreasing specific power, the capacity factor increases.

We increased the cost for a turbine in this study from previous NREL studies to reflect impacts from higher inflation, commodity prices, interest rates, and supply chain constraints that have been widely reported (Lloyd-Williams 2023), and which appear to have manifested in higher-cost wind turbine supply agreements. For example, Vestas reported that average selling prices for their land-based wind turbines increased by nearly 34% between the fourth quarter of 2021 and 2022, though they reported lower than average selling prices in the first quarter of 2023 (Vestas Wind Systems A/S 2022). Although there is some uncertainty in how long elevated costs will persist, we assume a turbine CapEx of $1,500/kilowatt (kW) for 2022, which represents an increase of 15% over the $1,300/kW value assumed in recent NREL cost studies (Stehly and Duffy 2022; Shields et al. 2021b). We assumed a cost of $1,500/kW for the 12-MW turbine, as well as the same costs regardless of whether a fixed or floating substructure was used. It is possible that wind turbines on top of floating substructures cost more, because of the additional impact of motion, which could include adding stiffness, a higher warranty cost, or cost of integrated load analysis in the front-end engineering design stage. However, because this cost increase is uncertain in how it should be applied across all floating designs, we assumed the same cost as fixed-bottom wind turbines.

3.1.2 Cost and Logistics Trade-Offs Related to Wind Turbine Upsizing

In this study, we determined the wind turbine nameplate capacity rating by considering some complex trade-offs between capital costs, supply chain deliverability, contracted power offtake agreements, and siting constraints. In commercializing offshore wind energy, lessons can be learned from the historic evolution of the commercial land-based wind industry. At the very start of the commercial land-based wind energy industry (1998–2003), wind turbine ratings were low (< 1.5 MW; Wiser et al. 2023). From 2004 to 2016, there was no significant upscaling of the land-based wind turbine rating (from 1.7 to 2.1 MW; Wiser et al. 2023). Even though the industry's impulse was to continue to upscale wind turbine size, some components such as towers and blades became too large to transport under inland bridges, and nacelle mass and tower heights reached the limits of conventional heavy-lift cranes. The result, however, was that the costs declined significantly due to rapid industrialization of the wind turbine and balance-of-station assembly line components and their domestic supply chains. After 2016, wind turbine upscaling increased to some degree, but only after significant cost reductions had already been achieved (Wiser et al. 2023).

From 2004 to the present, the land-based wind energy industry has doubled the wind turbine nameplate rating with most of that upscaling happening in the past few years. By comparison, the offshore wind energy industry has increased the average installed turbine size by a factor of 3.5, from just over 2 MW to about 7.7 MW on average over the same period. Moreover, the industry has recently committed to a further doubling of turbine size to a 15-MW class. While we acknowledge that wind turbine upsizing was an important step in lowering offshore wind costs, it is also important to highlight that there are diminishing returns in further upscaling and significant technology and supply chain risks in doing so (Shields, Beiter, and Nunemaker 2022).

Wind turbine manufacturers make huge investments in developing new technology platforms and wind turbine prototypes. At the current 13-MW scale, new turbines would require new infrastructure to be built, requiring billions of dollars before any electricity is generated. This development would include port and vessel upgrades to accommodate such large structures in an already underdeveloped and stressed supply chain. Apart from added research and development and infrastructure costs, increases in wind turbine size also increase risk premiums reflected in project financing and original equipment manufacturer warranty reserves. This outcome is especially true as the size and weight of the wind turbines test the limits of materials and basic technologies such as bearing assemblies.

Building a new supply chain and assembly process to accommodate larger wind turbines can take years to develop, and therefore longer to realize the cost benefits. As a result, these benefits must be weighed against those related to industrialization and standardization, which were demonstrated by land-based wind energy experience. These trade-offs, especially the temporal component, are extremely complex and difficult to capture in the cost models used. As such, the cost results herein may not reflect the full realization of cost reductions due to industrialization and supply chain development and may downplay some of the uncertainty associated with upscaling.

3.2 Substructure Choice

In our cost model, we use monopiles and semisubmersibles as the substructures for fixed-bottom and floating offshore wind energy, respectively. The modeled mooring systems for the semisubmersibles adjust with water depth, such that more expensive mooring systems are modeled for deeper water depths. Semisubmersibles are the most common substructure technologies proposed by developers for offshore wind energy development in the United States in the next 5−10 years (Musial et al. 2022). Other substructures could also be feasible depending on the site selected, but a site-specific analysis is beyond the scope of this study. Substructure choice is influenced by a variety of factors, such as soil structure; available manufacturing; port and logistics infrastructure; vessels; costs; and regulatory provisions (e.g., wildlife noise disturbance during installation). We assume a 60-m water depth as a techno-economic threshold between fixed-bottom (less than 60 m) and floating (greater than 60 m) offshore wind substructure deployment. While it is possible that technologies will be developed for fixed-bottom platforms that can be installed in deeper water (or shallower water, depending on substructure type), it is uncertain when or if such development will occur. Therefore, we felt the 60-m depth is a reasonable assumption for current technologies.

3.2.1 Precommercial and Commercial-Scale Timing Assumptions

Corresponding to the current commercial status of available substructures in the United States and globally (Musial et al. 2022), we represented fixed-bottom offshore wind at a commercial scale (i.e., 1,000 MW) and floating offshore wind at a precommercial scale (i.e., as multiturbine projects below 100 MW) in our baseline year of 2025. For both fixed and floating wind turbines, larger plant size increases absolute costs but not unit costs (per megawatt of installed capacity or per megawatt-hour (MWh) of delivered power), because project-level economies of scale remain important even if there are supply chain bottlenecks and project development uncertainties. We assume that floating offshore wind energy projects will reach commercial scale (and cost levels) during the early- to mid-2030s based on global market data. Therefore, we present floating offshore wind energy costs from 2030. This representation of floating offshore wind energy is different than prior assessments NREL has conducted for BOEM (Beiter et al. 2016, 2020), for which we assumed mature floating offshore wind energy supply chains were available at all years prior to 2020. The cost pathways for floating offshore wind as reported in this study rely on U.S. and global technological and commercial advancements in floating offshore wind deployment in deep waters, as well as a concurrent build-out of the supporting manufacturing, ports, and supply chain infrastructure.

4 Annual Energy Production

4.1 Wind Resource and Wave Data

For this assessment, we adopted two new offshore wind resource datasets that have recently become available for the Atlantic, Gulf of Mexico, and Hawaii. The National Offshore Wind dataset[13] (NOW-23) enhances the prior Wind Integration National Dataset (WIND) toolkit data by extending the resource data to 21 years (rather than 7 years) and providing additional validation of that data (Bodini et al. 2023; Draxl et al. 2015). The wind resource datasets used for each region can be different depending on what regions are available (Table 2). The NOW-23 dataset was produced by using global ERA-5 Reanalysis data (Hersbach et al. 2020) to initialize the regional Weather Research and Forecasting model (version 4.2; Skamarock et al. 2021) at a 6-hour refresh rate (how often the ERA-5 data are used to initialize the model). The initial horizontal grid spacing is 6 kilometers (km) with a nested domain of 2 km. The model is run with 61 vertical levels including 12 in the lower 300 meters of the atmosphere. We used the Yonsei University scheme for the planetary boundary layer and MM5 scheme for the surface layer in the Weather Research and Forecasting model runs. Outputs are available in a 5-minute resolution from 2000 to 2020. The significant height of combined wind, waves, and swell was taken from ERA5 Reanalysis data (Hersbach et al. 2020), which represents the mean height of the highest third of surface ocean waves generated by wind and swell. The waves have a 0.5-degree spatial resolution.

Table 1. Wind Resource Data Used in This Study

Region	Data Source	Modeled Years	Notes
Gulf of Mexico	NOW-23 (Bodini et al. 2023)	2000–2020 (21 years)	Generated in separate model run as Atlantic regions
Hawaii	NOW-23 (Bodini et al. 2023)	2000–2019 (20 years)	Has not been checked for bias as floating lidar has only been deployed recently (Showalter 2023)
Central Atlantic	NOW-23 (Bodini et al. 2023)	2000–2020 (21 years)	Generated in separate model run as North Atlantic
North Atlantic	NOW-23 (Bodini et al. 2023)	2000–2020 (21 years)	Generated in separate model run as Central Atlantic
South Atlantic	Wind Toolkit (Draxl et al. 2015)	2007–2013 (7 years)	NOW-23 extension in progress
West Coast	Wind Toolkit (Draxl et al. 2015)	2007–2013 (7 years)	Bias found in California Offshore Wind ‘20 (Bodini et al. 2022). Updates are underway for California. Pacific Northwest dataset has not been checked for bias as there is no floating lidar in the area

[13] See NREL (2024).

4.2 Gross Energy Production

We calculate gross energy production for every site, which represents the ideal energy production without losses and solely depends on the turbine power curve and wind resource. It can be expressed in terms of gross capacity factor, or the fraction of the year the idealized plant would have to operate at rated power to produce the gross energy production. To calculate the net energy production, the sum of all energy losses must be subtracted from the gross energy production.

4.3 Loss Categories

We identified five main sources of energy loss that we use to calculate net energy production including wakes, the environment, technical, electrical, and availability. As an example, mean values of these types of energy losses are given for the North Atlantic region for a 12-MW turbine (Table 2).

Wakes are regions of reduced velocity and increased turbulence that form behind a wind turbine as it extracts momentum from the wind to generate electricity. In addition, they have consequences for wind turbines downstream (in the wake). Wakes primarily cause reduced power production and increased wear and tear (mechanical loads). The level of wake losses changes with how the wind turbines are arranged to form the wind power plant. In this study, we assume a generic square grid wind turbine layout with turbines spaced 7 rotor diameters apart in the north-south and east-west directions. We did not account for cluster wake effects from neighboring wind plants, which can be significant (Pryor et al. 2021; Lundquist et al. 2019).

We have used the FLOw Redirection and Induction in Steady State (FLORIS) model (see Section 6.1.2) to evaluate wake losses for a 1,000-MW offshore wind plant using the wind resource datasets specified earlier (Section 4.1).

Table 2. Types of Losses Contributing to Modeled Net Energy Production

Type of Loss	Mean Value (% of Gross Energy Production)	Description
Wake (internal effects only)	7.2%–8.1%	Calculated using the FLORIS model for wind plants with wind turbines spaced 7 rotor diameters apart on a square grid
Environmental	1.59%	Includes hurricane, lightning, and temperature-related shutdowns (Beiter et al. 2016)
Technical	1% for fixed and 1.2% for floating	Power curve hysteresis (shutdown and restart near cut-out wind speed), onboard equipment power usage, rotor misalignment (Beiter et al. 2016)
Electrical	4.2%	Export cable system losses to environment, function of distance to point of interconnection (export cable length) (Beiter et al. 2016)
Availability	7.2%	Shutdowns for maintenance and repair, other system shutdowns

Losses will vary, and the static values provided here are either modeled values (e.g., wake loss output from the FLORIS model) or assumed from industry expertise (e.g., technical losses). For example, wake losses will be higher when accounting for external wakes, rather than only the internal ones considered in this analysis. As discussed in the next section, we expect technology improvements to drive a reduction in losses over time.

4.4 Net Energy Production and Net Capacity Factor

Net energy production is the total energy production generated by the wind plant, but with energy losses (Section 4.3) already subtracted. Energy production is influenced by turbine technology and wind resource quality (which varies spatially). Net energy production can be determined using the NCF, or the percentage of the total power output generated by the wind plant divided by the theoretical maximum power capability. NCF is the net energy production normalized by plant capacity and multiplied by the number of hours in a year. Therefore, it is a good metric to compare the efficiency of wind plants across an area. NCF will improve in conjunction with technological advancements, so we rely on an elicitation of wind energy experts to project future performance improvements for offshore wind plants (Wiser et al. 2021). We fit a learning curve to match the total performance improvement anticipated by 2035 (Figure 1). We also account for the fact that respondents' expectations were reported relative to fixed-bottom offshore wind energy in real 2019 terms and assume the same total percentage improvement for both fixed-bottom and floating offshore wind performance over time. Regional maps of NCF are provided in Section 7.

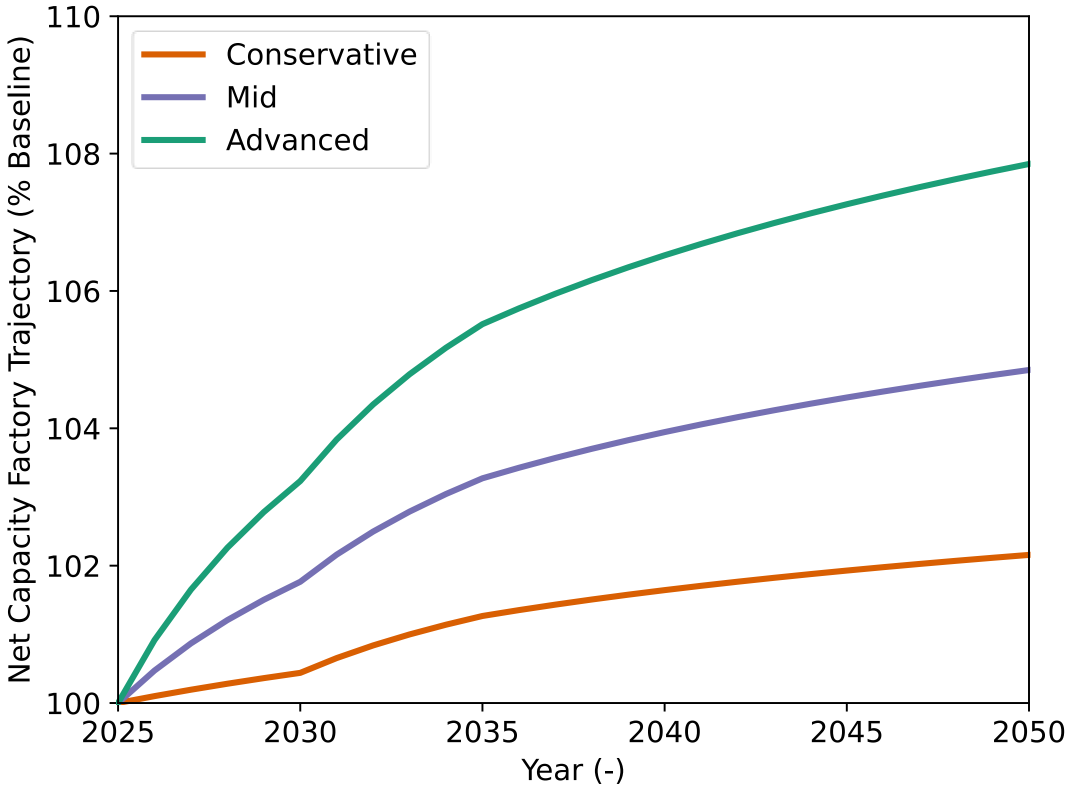

Figure 1. Performance (net capacity factor) improvement trajectories by scenario.

Note that the values in the plot are presented in terms of percent of the baseline 2025 performance. The data shown are not capacity factors.

5 Infrastructure and Logistics

5.1 Construction and Operation Ports

Our reevaluation of assembly and installation components focused on identifying construction and operation ports. Construction or assembly ports are used for assembly and integration of offshore wind turbines. Operation ports can be smaller and are used for routine operations and maintenance (O&M) activities. We assume that O&M ports for floating wind turbines cannot have an overhead restriction because fully assembled turbines are towed back to the port for maintenance and are too tall to pass under bridges or other overhead restrictions.

Since earlier NREL studies were conducted, more information has become available about the ports that are actively under development for use in offshore wind energy activities or under consideration. We selected construction and operation ports using internal NREL analysis and filtered data based on certain criteria (Table 3). These criteria were then used in the modeling assumptions in the study for calculating relevant distance to the associated port from the site. There is no limitation imposed on the distance from the site to the port, but the model will assume the closest relevant port from the site in the cost analysis. Furthermore, we do not consider the case where there is a feeder-barge-type installation in areas without a port, which could underestimate the actual "port" distances to the installation site if they were included. The list of ports was compiled using a mixture of previously published studies and direct contact with relevant stakeholders.

Table 3. Criteria for Selecting Ports Used in the Cost Study

Port Function(s)	Assumptions
Assembly and operations and maintenance (O&M) for both fixed-bottom (marshalling) and floating wind turbines (staging and integration)	No overhead restrictions and enough space for assembly in either previously published reports or discussion with stakeholders
O&M port for both fixed-bottom and floating turbines	Does not have any overhead restrictions but too limited in space and/or not equipped for assembly
O&M port for only fixed-bottom turbines	Has overhead restrictions and too limited in space and/or not equipped for assembly

U.S. ports are typically smaller than those used for offshore wind energy activities in Europe and the sector will have to invest heavily in port infrastructure to develop the infrastructure needed to facilitate commercial-scale deployment. Most ports will require navigation channels, berth pockets, and protected harbors to be dredged; wharfs and staging areas to be strengthened; and upland areas to be cleared and prepared. On the East Coast, most ports have limited expansion potential because they are already located in congested or urban areas (Parkison and Kempton 2022). This constraint may lead to a distribution of ports that service offshore wind energy projects instead of having fewer, larger ports.

Shields et al. (2023c) identified eight ports[14] on the East Coast that have conducted development activities or announced their intention to serve as marshaling ports for fixed-bottom offshore wind projects. We estimate that these ports are likely sufficient to be able to support the existing pipeline of East Coast projects through 2030; however, these ports are still not fully funded and additional financing is required to get them ready on time to support these projects. Shields et al. (2023c) estimated that at least $2 billion would be required to expand these ports, although this number likely increased since the publication of the report due to inflation. Furthermore, rising interest rates have impacted port construction just as they have for offshore wind energy projects and other areas of the broader economy (Musial et al. 2023b).

Floating wind staging and integration ports will likely need additional capabilities to assemble a wind turbine on top of a floating platform prior to towing it out to the project site. Shields et al. (2023c) estimate that the West Coast could require between 4 and 9 staging and integration sites and 8 and 17 O&M sites to deploy and maintain 25–55 GW of floating offshore wind projects by 2045, corresponding to an investment of $5−$11 billion. Additional port investment could be required as the industry expands into other regions such as the Gulf of Mexico.

Port development requires a significant amount of upfront capital, which was not included in the modeled costs in this study. For context, the capital costs for a 1,000-MW fixed-bottom offshore wind project averaged around $3.5 billion between 2018 and 2022 (Musial et al. 2023b). Using these cost estimates, the Biden administration's pathway to deploy 110 GW of offshore wind by 2050 could have a capital value of over $300 billion (The White House 2021). In this context, an investment of $10−$15 billion in port infrastructure would represent around 5% of the sector's total expenditure.

5.2 Points of Grid Interconnection

We identified POIs using recently published studies (Fuchs et al. 2023; Brinkman et al. 2024; Cooperman et al. 2022; Novacheck and Schwarz 2021; Severy and Jacobson 2020; Shields et al. 2021a; The White House 2021). These POIs include those that are actively being constructed or upgraded for use in offshore wind energy projects or are being considered by projects in development. To fill in gaps of coastline not covered by prior studies or our internal POI database, we filtered POIs of 230 kilovolts or higher from the Homeland Infrastructure Foundation-Level Data dataset made available through the U.S. Energy Atlas, maintained by the Energy Information Administration. Higher-voltage POIs are considered more likely to be adapted for large power injections from offshore wind plants. It should also be noted that each wind plant project point is assumed to build its own connection to the nearest point of interconnection, when in reality, there are some proposed offshore backbone systems under consideration off the east and west coasts. Introducing backbone export systems could reduce costs of transmitting power back to shore.

5.3 Vessels

We assumed an appropriate vessel type according to different tasks in the assembly, installation, operations, and maintenance of the modeled offshore wind plants. These vessels include cable-

[14] Ports include the New Bedford Marine Commerce Terminal, New London State Pier, Portsmouth Marine Terminal, New Jersey Wind Port, Tradepoint Atlantic, South Brooklyn Marine Terminal, Port of Salem, and Arthur Kill Terminal.

lay vessels, feeder, heavy-lift, scour protection, towing, and support vessels. For more information about how the vessels are used for modeling the installation and assembly of wind power plants, see Nunemaker et al. (2020). For routine maintenance and repair of wind turbines, we assumed crew transfer vessels or service operations vessels. For major component replacements, we assumed the use of a jack-up vessel for fixed-bottom wind turbines whereas floating turbines were modeled to be towed to port (Section 6.4, Hammond and Cooperman (2022). Limitations in vessel availability have the potential to increase costs; however, including timing of vessel availability was beyond the scope of this study.

6 Cost Modeling Approach

In the previous sections, we outlined the motivation for a long-term cost analysis, including the current cost environment and cost scenarios (Section 2) and our technology assumptions (Section 3), as well as how annual energy production is calculated (Section 4). In addition, we described our selection of infrastructure required to build offshore wind plants (Section 5). Next, we present our cost modeling approach used to calculate LCOE.

For our cost estimates, we consider expenditures for offshore wind system components (e.g., wind turbine, fixed or floating substructure, and export cable system), installation activities (e.g., port logistics and vessel operations), and O&M (e.g., replacement parts and vessel operations). Together with the cost to finance the initial capital expenditure and energy yield from the offshore wind plant, we report the lifetime project expenditures as the LCOE (Eq. 1). This metric helps express the project expenditures on an annualized ($/MWh) basis for comparison with alternative generation options (Short, Packey, and Holt 1995).

$$LCOE = \frac{(FCR * CapEx) + OpEx}{AEP_{net}} = \frac{FCR * (C_{Turbine} + C_{BOS}) + C_{Ops} + C_{maint}}{AEP_{net}} \qquad (1)$$

where:

LCOE = levelized cost of energy ($/MWh)
FCR = fixed charge rate (%/year)
CapEx = capital expenditures ($/kW)
AEP_{net} = net average annual energy production (MWh/year [yr])
OpEx = average annual operational expenditures ($/kW-yr)
$C_{Turbine}$ = wind turbine capital expenditures ($/kW)
C_{BOS} = balance-of-system capital expenditures ($/kW)
C_{ops} = operational expenditures ($/kW-yr)
C_{maint} = maintenance expenditures ($/kW-yr).

We report LCOE in nominal terms and denoted in $2022, unless reported otherwise. Our representation of LCOE does not include any tax incentives (e.g., the federal investment or production tax credit) or other direct project subsidies. However, we acknowledge that tax credits are important in influencing project economics (Zoellick et al. 2023), with the exact impacts depending on which bonus credits a project qualifies for. When we give an LCOE value for a specific year, we are referring to the projected costs for the commercial operation date (COD) in $2022. We present unsubsidized LCOE values at the point of electricity grid interconnection.

We made several advancements in our cost modeling to represent the latest developments in the offshore wind energy sector. At the start of this study, we identified offshore wind energy components (Table 4) that have changed considerably in either cost or technology over the past 3–5 years, have a relatively high impact on LCOE, and have available data to validate cost. We updated several cost components in our NREL model toolset for this study. Together, the reassessed components comprise approximately 80% and 84% of the overall CapEx and OpEx contributions to LCOE of a typical offshore wind energy system, respectively, as outlined in Stehly and Duffy (2022). In addition to these CapEx and OpEx components, we have also reassessed the wind turbine capacity factor and financing.

Table 4. Cost Components Analyzed for This Study, Adapted From Stehly and Duffy (2022).

☑ = Re-assessed for this study; ⊙ = Calculated as a proportion of CapEx components.

Component		Fixed Bottom	Floating	
		Typical share of LCOE		Updated modeling approach from previous NREL spatial cost studies
CapEx	Wind turbine	22%	17%	☑
CapEx	Development and management	2%	1%	⊙
CapEx	Substructure and foundation	9%	27%	☑
CapEx	Export system cable	8%	8%	☑
CapEx	Array system cable	3%	3%	
CapEx	Grid connection	1%	1%	
CapEx	Assembly and installation	7%	4%	
CapEx	Lease price	1%	2%	
CapEx	Soft costs (including plant decommissioning, contingency, construction finance, and insurance during construction)	15%	11%	⊙
OpEx	Operations	9%	7%	
OpEx	Maintenance	24%	20%	☑
Annual Energy Production	Gross capacity factor	n/a	n/a	☑
Annual Energy Production	Wake losses	n/a	n/a	☑
Annual Energy Production	Other losses	n/a	n/a	
Cost of Finance	Financing	n/a	n/a	☑

We conducted several of the underlying analyses to update the cost assumptions for a 600-MW plant for direct comparison with earlier NREL studies but were scaled to a 1,000-MW plant to correspond to the intended plant size of this study. This scaling includes semisubmersible, monopile, and export cable costs (Appendix A), as well as OpEx costs (Appendix B).

6.1 Cost and Energy Yield Models

For estimating offshore wind energy development cost at any given site, we used several integrated modules with NREL's National Renewable Energy Laboratory Wind Analysis Library (NRWAL)-Renewable Energy Potential (reV) modeling environment (Table 5). Each of the models captures cost components and energy yield performance from individual line items at a medium to high fidelity.

Table 5. Cost and Performance Modules Used for This Analysis (Adapted From Duffy et al. (2022])

Component	Module	Source
Wind resource	reV	Maclaurin et al. (2021)
Wake losses	FLORIS	NREL (2021)
CapEx and OpEx	NRWAL	Nunemaker et al. (2023)
Electrical system, environmental, and other	NRWAL	Beiter et al. (2016)
Learning curve	Forecasting Offshore Wind Reductions in Cost of Energy (FORCE)	Shields, Beiter, and Nunemaker (2022)

The model framework (Figure 2) takes inputs of various spatial data (e.g., wind speed, locations of ports and POI, water depth, and wave height), as well as assumptions made for wind turbine rating and plant size, some known costs used for calibration and model validation. Other inputs used to calculate the baseline LCOE are outputs of other models. The outputs of various models (e.g., reV, FLORIS, Offshore Renewables Balance-of-system and Installation Tool [ORBIT], Windfarm Operations and Maintenance cost-Benefit Analysis Tool [WOMBAT], NRWAL-Finance) are processed and compiled into a cost curve database called NRWAL (blue box in Figure 2). Most of these cost curves require various spatial data (e.g., water depth or location of points of interconnection) to output an actual cost value (e.g., a component of CapEx like export cable cost). These calculated cost components that comprise CapEx and OpEx are used to calculate the baseline LCOE (defined here in 2022 U.S. dollars [USD]) using Eq. 1 (Section 6). After the baseline LCOE value is derived, we applied cost projections for each scenario to understand how offshore wind plant costs may evolve as the industry matures.

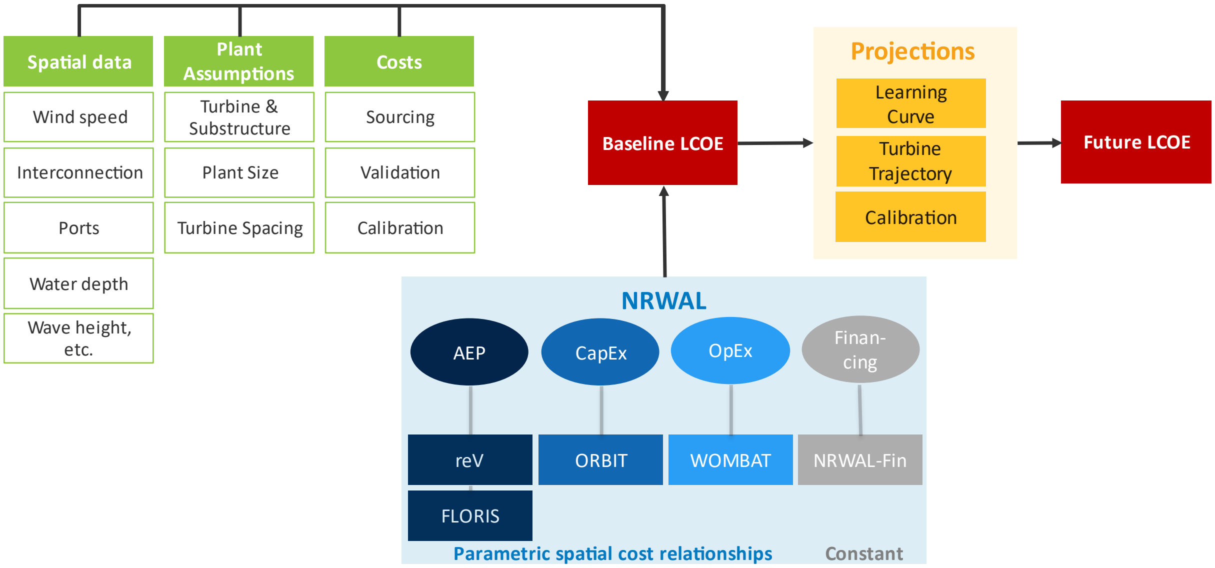

Figure 2. Model framework used by reV to derive cost parameters

6.1.1 Renewable Energy Potential Model

We used the reV model (Maclaurin et al. 2021) to calculate gross capacity factors from hourly wind resource data at turbine hub height. Beyond this functionality, we used reV's capability to integrate with other models (described in the following sections) that represent our assumptions about offshore wind energy infrastructure, such as POIs, construction and operations ports, cable routing, site-specific wake effects, and cost trajectories.

6.1.2 FLOw Reduction and Induction in Steady State

FLORIS[15] is NREL's suite of engineering wake modeling software tools written in Python. We used FLORIS version 3.4 to model wake losses at thousands of sites across the United States while also accounting for site-specific wind resource data. We used the Gauss-Curl-Hybrid wake model and adjusted model tuning parameters based on the recommendations of the FLORIS development team at NREL. We assumed an average offshore turbulence intensity of 6% and a generic square grid plant layout with turbines spaced 7 rotor diameters apart in north-south and east-west directions. For the sensitivity of wake loss to the choice of wake model and other input parameters in FLORIS, see Fleming et al. (2023) and Cooperman et al. (2022).

6.1.3 NREL Wind Analysis Library

The NRWAL library includes key equations for the relationships between individual offshore wind energy cost components, project size, turbine nameplate capacity, and spatially dependent parameters (e.g., wind speed, water depth, and distance to ports and interconnection). Together, they form a comprehensive library for the installation, operation, and financing of an offshore wind energy project. NREL regularly validates and updates the cost relationships in this library from publicly available market data, industry and stakeholder consultation, and bottom-up modeling studies using primarily the ORBIT (Nunemaker et al. 2020) and WOMBAT (Hammond and Cooperman 2022) models.

[15] FLORIS is available on GitHub: https://github.com/NREL/floris.

6.1.4 Forecasting Offshore Wind Reductions in Cost of Energy

We used the Forecasting Offshore Wind Reductions in Cost of Energy (FORCE) model to derive learning rates (Section 6.7) for fixed-bottom and floating offshore wind technologies (Shields, Beiter, and Nunemaker 2022). Such learning rates express the percent reduction for each doubling of installed offshore wind energy capacity globally. We obtained the learning rates empirically with a linear regression of global fixed-bottom offshore wind project CapEx data. The model also reports bounds around the learning rate point estimate that reflects the uncertainty in historical cost data, which we use to define "conservative" (expensive) and "advanced" (less expensive) scenarios. Because cost reporting across a wide array of global offshore wind energy projects is typically limited to CapEx, we use cost reduction estimates derived from expert elicitation (Wiser et al. 2021) for projecting OpEx.

6.2 Macroeconomic and Supply Chain Drivers for the Offshore Wind Energy Industry

The offshore wind energy industry has reported significant cost increases since 2021 because of the rising cost of capital, higher commodity prices, and supply chain constraints. The secured overnight financing rate (SOFR) underlying the debt interest rate has soared from just above 0% to 5% between 2020 to 2023 (Figure 3). Because offshore wind assets are highly capital-intensive, even a relatively small uptick in SOFR (and thereby financing costs) can cause a large increase in LCOE.

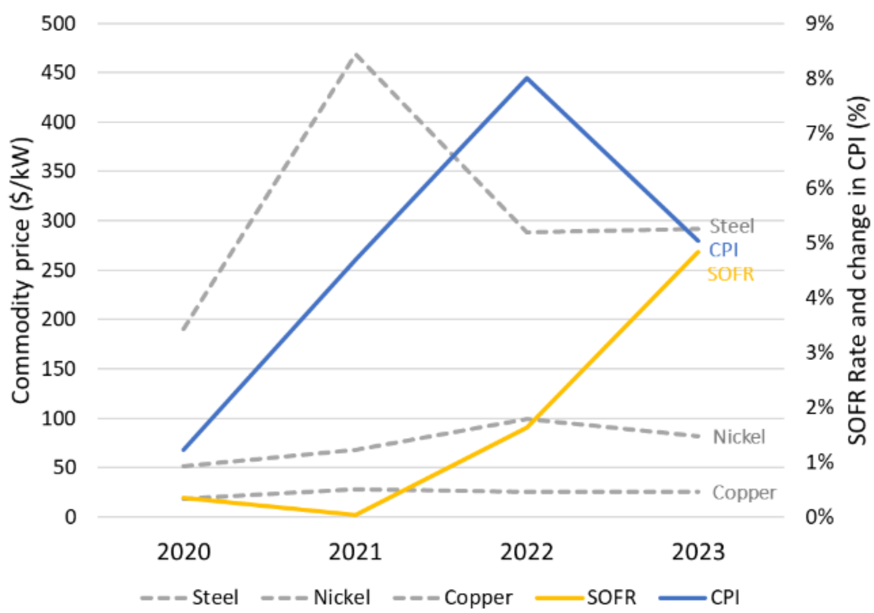

Figure 3. Key cost drivers between 2020 and 2023. ***Figure created using data from Federal Reserve Bank St. Louis (2023); U.S. Bureau of Labor Statistics (2023); Trading Economics (2023); Cooperman et al. (2023)***

Note: CPI = consumer price index.

At the same time, the prices for major commodities used in offshore wind plants (Eberle et al., 2023) have increased between 2020 and 2021, such as steel (+41%), nickel (+76%), and copper (+68%) and shown considerably higher levels of fluctuation than observed in the prior decade.[16] Since 2022, several of these metals have experienced a decline in price levels while others (e.g., fabricated steel plates) remain high. Figure 4 underscores the impact of these factors in a comparison of original offshore renewable energy certificate (OREC) strike prices of four New York offshore wind projects with price adjustments requested by developers (top of the bars in the figure). A weighted average of these requested price adjustments suggests up to a 50% increase in LCOE from 2021 to 2023.

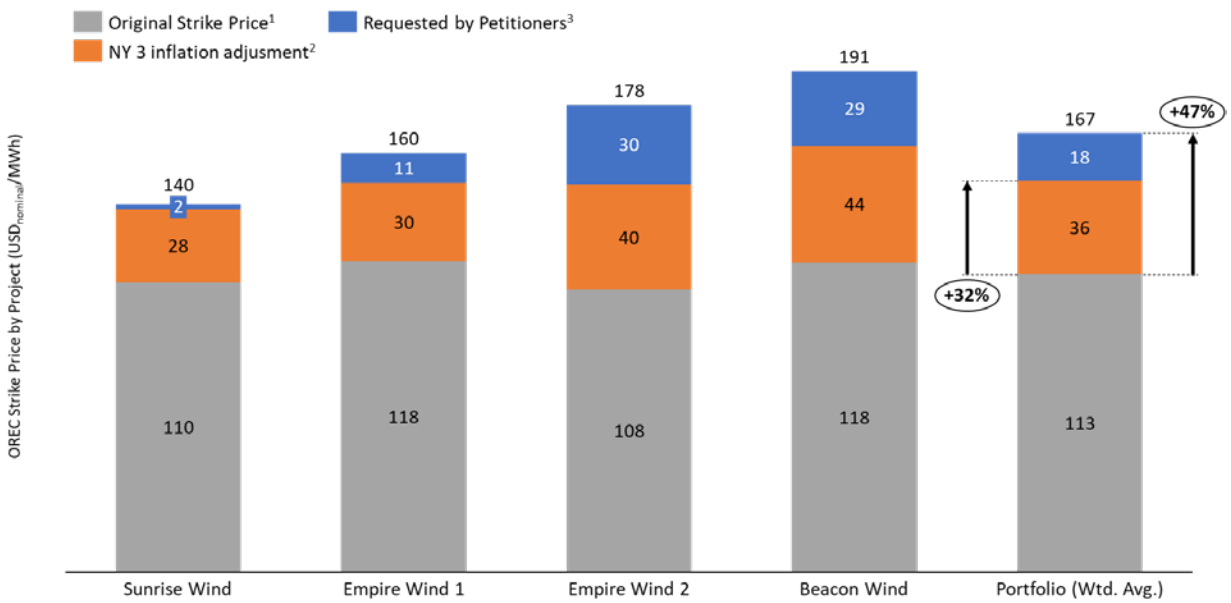

Figure 4. Petitioned price adjustments for four New York projects.

Notes: 1) The original OREC strike price agreed upon in solicitation ORECRFP18-1 (NY1) and solicitation ORECRFP20-1 (NY2); 2) the OREC strike price based on NY3 inflation adjustment based on commodity indices for labor, fabrication, steel, diesel, and copper as of June 2023; 3) requested OREC price by offshore wind petitioners (i.e., Sunrise Wind, Empire Wind 1, Empire Wind 2, and Beacon Wind). Note that the petitioned price levels may reflect ITC election by the petitioners. A direct comparison to LCOE should factor in several differences between offtake prices and LCOE (Beiter et al. 2021).

Persistent supply chain disruptions caused by COVID-19, global demand for offshore wind and maritime goods and services exceeding supplies, conflicts such as the Russia-Ukraine war, and a slower-than-anticipated build-out of domestic U.S. manufacturing, including vessels and ports, have further caused cost increases to the U.S. offshore wind energy sector. These impacts can result in higher wind turbine pricing, vessel day rates and project delays.

In the following sections, we describe our approach to modeling capital, operational, and financing costs. We used the petitioned price levels (Figure 1) to validate the baseline cost levels for 2023. The high costs from commodity prices and supply chain bottlenecks observed in markets today could return to longer-term average levels soon, but they might also persist at their

[16] Prices for the commodities shown in Figure 2 are typically reported in terms of $/ton. We have converted those to $/MW to allow for a more direct comparison to the CapEx estimates in this report. Amounts of commodities for a typical offshore wind plant were sourced from Cooperman et al. (2023).

current levels or increase further. Although we have done our best to capture the presently higher costs, high levels of cost uncertainty remain, which we illustrate by presenting a range of baseline costs and long-term trajectories (see Section 6.7) and conducting a sensitivity analysis of key cost uncertainties (see Section 7.4).

6.3 Capital Costs

In this section, we describe the new modeling approaches used to update major cost components (those with a check mark in Table 4). Wind turbine costs are covered separately in Section 3.1.1.

6.3.1 Fixed-Bottom Substructure and Transition Piece

This study uses a monopile to estimate the substructure costs for fixed-bottom offshore wind energy projects. We used NREL's ORBIT to run a parametric sweep over a range of water depths and wind turbine ratings and to estimate monopile cost and mass for each point in the design space. ORBIT implements a simple method developed by Arany et al. (2017) to size a monopile based on site characteristics (e.g., wind speed, wind turbulence intensity, water depth, wave height, and wave period), wind turbine characteristics (e.g., rated power, rated wind speed, rotor diameter, cut-in/cut-out speed), and ground profile (soil stiffness) (Nunemaker et al. 2020). The mass of the transition piece is then estimated by assuming it is a simple steel cylinder with a diameter slightly greater than that of the monopile. As a result, we can develop specific estimates for monopile designs throughout the design space and fit cost curves to these data (Appendix A.1) that are then implemented in the NRWAL code repository (Section 6.1.3). This approach replaces the method used in previous NREL analyses (e.g., Beiter et al. 2016), which fit cost curves to empirical data for monopiles used for 3- to 10-MW wind turbines, and then extrapolated to larger wind turbine ratings. When developing these costs, we assumed a representative plant size of 600 MW with a mean wind speed of 9 meters per second. Installation costs are not included in this design space but are included in NRWAL as a separate line item.

6.3.2 Floating Substructure

This study uses a steel semisubmersible to estimate the substructure costs of a floating wind project. Like our representation of the monopile costs, prior NREL analyses estimated semisubmersible platform costs by deriving a cost curve based on industry-sourced data for 3- to 10-MW wind turbines and then extrapolated to higher turbine ratings as necessary. For this study, we implemented a bottom-up, scalable semisubmersible design module in ORBIT and used this module to generate a cost curve for the floating substructure costs (Appendix A.2).

6.3.3 Export System

The export system used to transmit power from the offshore wind project to the onshore point of grid interconnection comprises an offshore substation, electrical cables, and (in some cases) onshore power conversion infrastructure. Export cables are either high-voltage alternating current (HVAC) or high-voltage direct current (HVDC), each of which has separate power conversion equipment needs in the offshore and onshore substations. HVAC systems (particularly the offshore substation) tend to be cheaper but result in higher electrical losses that increase with cable length. As a result, there is a "crossover point" at roughly 60–70 km wherein HVDC systems become cheaper projects with long enough distances from a point of interconnection.

We updated the electrical system design tools in ORBIT to support both HVAC and HVDC system design and assumed HVAC at shorter distances and HVDC at longer distances, given that this assumption is more economical. The module changes the size of the power conversion equipment on the offshore substation including power transformers, shunt reactors (HVAC only), switchgear (HVAC only), DC breakers (HVDC only), and ancillary systems. It then estimates the number of cables needed to transmit the full power capacity of the project (either HVAC or HVDC cables) and, for HVDC systems, the onshore converter cost to convert power back from DC to AC. Finally, ORBIT estimates the mass and cost for the structural elements of the offshore substation (the topside building and substructure). The export system cable cost is parametrized as a function of cable length (Appendix A.3). Our assumed cable length is a straight line from any offshore wind site to the intersection with the coastline point that is in route to the nearest POI. A grid connection cost to account for connecting the export cable to the POI was also added to the final export cable cost. Floating substations and deep-water cable connection will add cost to floating offshore wind plants, but due to the high uncertainty in these values, this extra cost was not included.

6.4 Operations and Maintenance Costs

We generated O&M cost curves (Appendix B) using WOMBAT (Hammond and Cooperman 2022). This tool was developed by NREL and provides the ability to perform spatial cost assessments.

There are two O&M cost categories we considered: maintenance, which includes the materials, labor, and vessel operation costs; and operations, which is typically a (relatively) fixed value and assumed to be $30/kW-year (Stehly and Duffy 2022). Labor rates are not considered regionally and assumed to be constant on the national scale. WOMBAT simulates scheduled and unscheduled maintenance for a wind power plant based on user inputs that define failure probabilities and maintenance intervals for plant components. Failure rates for offshore wind plant components were based on Carroll et al. (2016) for fixed-bottom sites and Schwarzkopf et al. (2021) for floating sites. A change in failure rates for more recent wind turbines could impact O&M cost. Different vessels are used to access the site depending on the type of maintenance that is required. Crew transfer vessels or service operation vessels are used for routine maintenance and minor repairs. Cable repairs require a cable-lay vessel. Major component replacements are conducted using a jack-up vessel for fixed-bottom wind turbines, or at port after a towing operation for floating turbines.

The evolution of OpEx over time was derived for each scenario from a survey of wind energy industry experts (Wiser et al. 2021). We fit a learning curve (see Section 6.7 for details) to match the total cost reduction anticipated by 2035 and extended it to 2050. We accounted for the fact that respondents' expectations were reported relative to fixed-bottom offshore wind energy in real 2019 terms. Cost trajectories for OpEx, separated by technology (fixed or floating) and by cost scenario, show a decrease in OpEx with growing deployment (Figure 5).

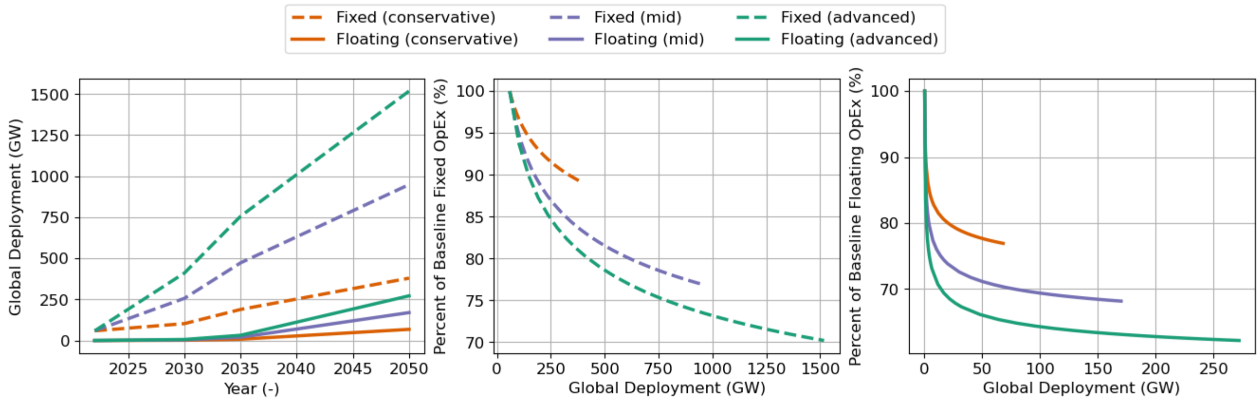

Figure 5. Global fixed-bottom and floating offshore wind deployment projections over time (left) and (right) percentage of baseline offshore wind project OpEx from industry learning under different scenarios relative to baseline values

6.5 Financing

Offshore wind energy assets are capital-intensive and require debt and equity financing. We consider financing costs as part of a fixed charge rate (FCR) (Short, Packey, and Holt 1995), which is multiplied with CapEx (Eq. 1). The FCR annualizes the upfront capital cost expenditure that is incurred for constructing an offshore wind plant (i.e., converting the one-time capital expenditure into annualized $/MWh units). FCR is not intended to capture all of the complex (and project-specific) financing decisions that would be made for a real offshore wind energy project, such as pre-final investment decision spending by a developer or the varying return expectations of different investors over the project life cycle. Instead, FCR estimates how broader economic conditions (i.e., inflation) and sector-specific parameters (e.g., debt rate) affect the cost of capital. Financing costs are typically reported as the weighted average cost of capital (WACC).

For deriving WACC, we rely on a recent elicitation of 70 global experts on the cost of financing (Taylor, Beiter, and Egli 2023). This expert elicitation suggests a cost of equity of 9% and a debt share of 60% for U.S. offshore wind energy projects in 2021. We increased the reported 3.9% cost of debt by 2% to account for the increase in SOFR rates between 2021 and 2023. The resulting nominal WACC (after tax) of 6.1% (Table 6) is slightly higher than the rate of 5.4% from prior nationwide cost assessments by NREL, mostly due to the higher cost of debt and lower share of debt. The construction finance costs incurred during an assumed 3-year construction phase are accounted for as a separate line item in the reported soft costs.

We used the same WACC (and by extension, FCR) for fixed-bottom and floating technologies. While early-stage floating offshore wind projects are likely to incur a higher WACC, they are expected to be relatively similar once floating offshore wind projects reach commercial scale (Weber 2021).

Table 6. The Cost of Financing Used in This Study. ***Based on Taylor, Beiter, and Egli (2023) and Stehly and Duffy (2022)***

FCR (nominal) (after tax)	%	7.7%
FCR (real) (after tax)	%	5.7%
WACC (nominal) (after tax)	%	6.1%
WACC (real) (after tax)	%	3.5%
Capital Recovery Period	yr	30
Share of debt	%	60%
Debt rate (nominal)	%	5.9%
Equity Return (nominal)	%	9%
Tax rate	%	26%
Inflation	%	2.5%
Depreciation Schedule		5-year MACRS

Financing conditions are subject to change as prevailing interest rates and technology, country, and offtake risks (Taylor, Beiter, and Egli 2023) change. These factors have been evolving over time, in part because of the underlying rates for debt financing and offshore wind energy's commercial maturity, and are often challenging information to obtain because of their confidential nature. As an example, interest rates (i.e., SOFR) have increased from just above 0% to 5% between 2020 to 2023, inducing a change in WACC of approximately 2%.[17] Such change in the WACC increases LCOE considerably because it affects all capital expenditures. Because of the high uncertainty (historically and going forward) and the considerable changes in LCOE incurred from fluctuating financing costs, we included a sensitivity indicating magnitudes of impacts from different changes in FCR on LCOE (Section 7.4).

6.6 Other Cost Components

The scope of this report limited the reanalysis to several select cost components. Others were adopted from prior studies. These combined components comprise roughly 20% of the total CapEx and OpEx of a typical wind farm.

The array system cable, which comprises a relatively small fraction of the overall CapEx, is calculated as a function of water depth and number of wind turbines (which varies with turbine rating given an assumed static 1-GW plant size). A 20% cost adder for dynamic cables is used for floating wind turbines. The methodology to calculate the array cable system is the same as the one used in (Musial et al. 2023a). The grid connection cost is a function of distance from cable landfall to the POI and wind turbine capacity. The lease price was included in our cost modeling and assumed to be $100 million USD, although in reality, this varies by region and can be modified in future regional studies.

6.7 Cost Projections

In this section, we explain our approach for estimating future fixed-bottom offshore wind energy project costs. We first rely on the bottom-up estimates from the spatial cost modeling process described earlier to obtain baseline costs (Step 1 in Figure 6). After calculating bottom-up costs based on geospatial parameters and technology choices, we seek to understand how offshore wind energy costs evolve over time. To do this, we develop projections of future CapEx in two

[17] Holding all else equal and with an assumed debt share of 55% and a combined tax rate of 28%.

parts: long-term cost projections based on global industry experience and near-term CapEx adjustments to account for macroeconomic conditions facing early U.S. offshore wind energy projects not captured in learning curves. Long-term projections of OpEx and wind plant performance (NCF) are informed by the expert elicitation detailed in Wiser et al. (2021).

Learning curves are often used to project future costs (Shields, Beiter, and Nunemaker 2022; Bolinger, Wiser, and O'Shaughnessy 2022). We rely on learning curves to develop cost projections because we expect costs to decrease in the long term as the industry matures, technology evolves, and supply chain develops. However, since learning curve projection methods do not appropriately consider the short-term macroeconomic conditions currently affecting the offshore wind energy sector (Section 2.1), we introduced a correction into the early years of the learning curve. By doing so, we attempted to account for the impact of near-term cost increases while representing the long-term cost impacts from industry learning (Steps 2 and 3 in Figure 6).

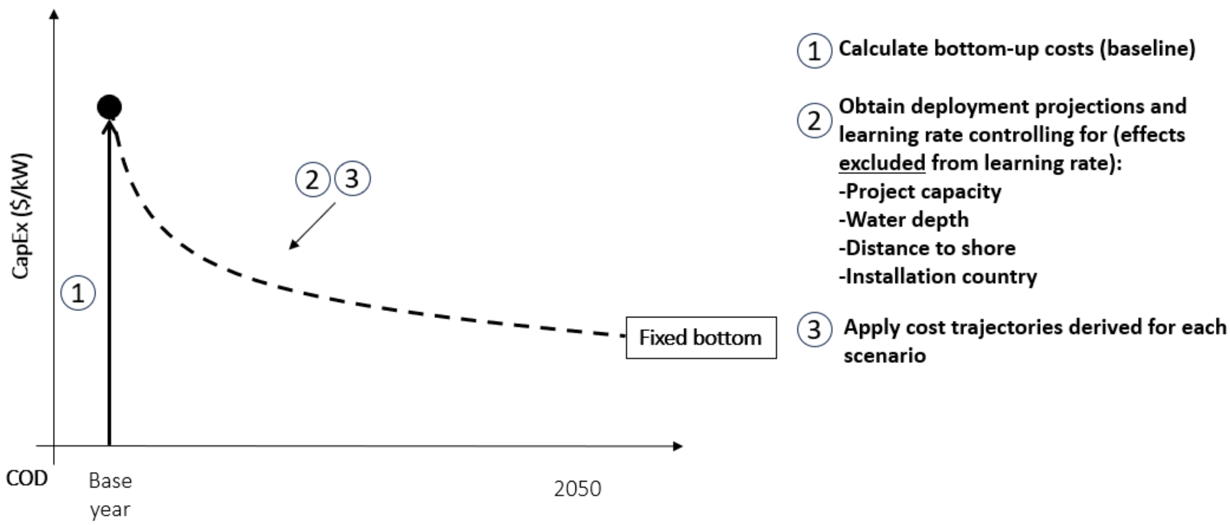

Figure 6. Process for projecting fixed-bottom offshore wind energy project costs over time

We repeat this process to develop projections under three scenarios to reflect uncertainty in both the long-term cost reductions from learning as well as the elevated costs in the short term. Specifically, we modeled a "mid" scenario that represents our best understanding of future costs, a "conservative" scenario, in which less-aggressive cost reduction and higher short-term costs lead to costs higher than the mid scenario, and an "advanced" scenario, wherein costs are lower due to more aggressive cost reductions and less significant impacts from short-term macroeconomic conditions. For more detail on these scenarios, see Section 2.2.

6.7.1 Establishing Baseline Floating Offshore Wind Energy Costs

NREL's bottom-up cost modeling tools were developed to model commercial-scale (defined in this study as ≥ 1 GW) project costs that reflect a mature floating offshore wind energy industry. The floating offshore wind industry is relatively immature compared to the fixed-bottom offshore wind industry, with global deployed capacities through 2022 of 0.123 GW and 59 GW, respectively (Musial et al. 2023b). The largest operational floating offshore wind energy project as of August 2023 is the 88-MW Hywind Tampen project off the coast of Norway (Equinor ASA 2023). Because floating offshore wind energy is in a nascent stage of development compared with fixed-bottom offshore wind, the bottom-up floating cost estimates must be adjusted to reach a realistic baseline. This approach accounts for the fact that demonstration projects (<100 MW) do not benefit from the same economies of scale as commercial-scale projects through amortizing fixed development costs over a greater number of megawatts as well as favorable procurement terms with suppliers. Previous NREL spatial cost modeling efforts have focused on capturing commercial-scale floating offshore wind project costs over the long term and assumed mature supply chains were available each year (Beiter et al. 2020; Shields et al. 2021b). In this report, we adopt the approach outlined in Shields, Beiter, and Nunemaker (2022) to better represent the cost reductions as the floating offshore wind energy industry matures.

To obtain baseline floating offshore wind energy project costs that reflect early-stage projects, we modified commercial-scale cost estimates obtained from NREL's bottom-up modeling tools. Demonstration-scale floating offshore wind project costs are estimated to be at least 2–3 times the costs of a commercial-scale floating offshore wind project deploying similar technology (Shields, Beiter and Nunemaker 2022; Musial et al. 2020, 2019). We adopt a scaling factor of 2.5 times across all scenarios to obtain baseline floating offshore wind costs (Steps 1 and 2 in Figure 7). Note that we couple this with more aggressive learning rates for floating offshore wind (discussed next), which includes cost reduction impacts as plants become bigger and the industry matures.

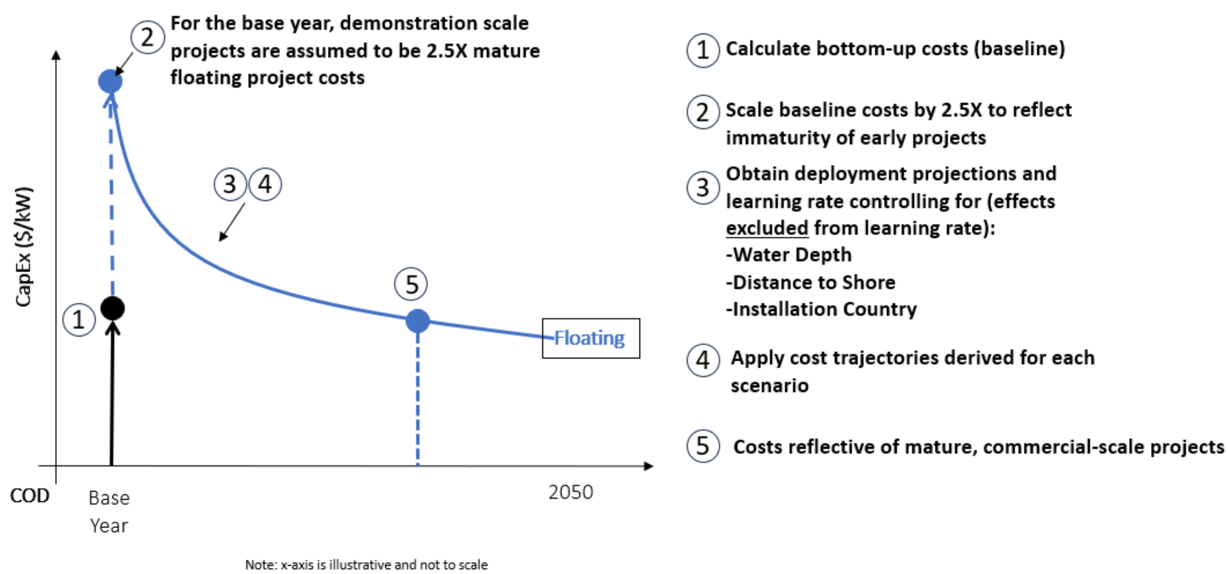

Figure 7. Process for projecting floating offshore wind energy cost reductions over time

6.7.2 *Long-Term Projections*

Learning curves describe cost reductions associated with producing more of a particular good or service (Louwen and Lacerda 2020). They are observed empirically for any form of industrial production and can be used to forecast future cost reductions. A learning rate describes the percentage cost reduction for every doubling of production (in this case global installed offshore wind capacity). So, with a high learning rate and significant growth installed capacity, we can expect a large reduction in cost over time.

We calculated learning rates for offshore wind energy project CapEx based on a regression of historical fixed-bottom offshore wind CapEx data and installed capacity data using NREL's

FORCE[18] (Section 6.1.4) model and the approach outlined by Shields, Beiter, and Nunemaker (2022). In the regression process, we control for spatial variables including water depth, distance to shore, and installation country to exclude their impacts on the learning rate. We deliberately do not control for wind turbine rating to include turbine upsizing effects in the resulting learning rate, meaning that cost reductions from future upsizing are included in the long-term cost projection.

For floating offshore wind energy, we use fixed-bottom project CapEx data because there are no sufficient data on operational floating projects (Musial et al. 2019). In the derivation of the floating learning rate, we included effects from economies of plant scale (by excluding this variable from the regression) because existing floating offshore wind projects are still at the pilot and precommercial stage. The empirical data used for the regression analysis, which primarily include commercial-scale European projects, may not capture the full benefits of transitioning beyond the precommercial stage of the industry. Regression variables and resulting learning rates by scenario are presented in Table 7. Refer to Shields, Beiter, and Nunemaker (2022) for additional information on the regression fit.

Table 7. Estimated CapEx Learning Rates and Regression Variables

Technology	Conservative	Mid	Advanced	Regression Variables (Effects Excluded From Learning Rate)
Fixed Bottom	6.3%	8.8%	11.2%	Water depth, distance to shore, installation country, plant rating
Floating	8.7%	11.5%	14.2%	Water depth, distance to shore, installation country

Note: Conservative and advanced CapEx learning rates are calculated as the experience factor +/- the standard error. Refer to Shields, Beiter, and Nunemaker (2022) for more discussion of the regression fit.

In addition to learning rates, we need projections of global offshore wind capacity over time (for both fixed and floating) to calculate the cost reductions from industrial learning. These reductions are calculated with averages of projections obtained from literature (Table 8 and Figure 8 [left]).

[18] The FORCE model is available on GitHub at: https://github.com/NREL/FORCE.

Table 8. Global Fixed-Bottom and Floating Offshore Wind Deployment Assumptions by Scenario

Year	Fixed-Bottom Conservative Deployment (GW)	Fixed-Bottom Mid Deployment (GW)	Fixed-Bottom Advanced Deployment (GW)	Floating Conservative Deployment (GW)	Floating Mid Deployment (GW)	Floating Advanced Deployment (GW)
2022	59	59	59	0.123	0.123	0.123
2030	103	257	411	1.6	4.0	6.4
2035	189	473	756	8.0	20.0	32.0

Fixed-bottom projections from the 2022 deployment obtained from Musial et al. (2022); other years informed by Bloomberg New Energy Finance (2023), International Renewable Energy Agency (2020), DNV (2022), Global Wind Energy Council (2021), and Wood Mackenzie (2022b).

Floating projections from the 2022 deployment obtained from Musial et al. (2022); other years informed by the Global Wind Energy Council (2022), Wood Mackenzie (2020), Hannon et al. (2019), DNV (2022), Aegir Insights (2023), ORE Catapult (2022), and 4C Offshore (2023b).

The resulting learning curves depict the cost reduction from learning with increasing global offshore wind energy deployment (Figure 8 [right]). Because both the learning rate and deployment trajectory are greater under the mid scenario than the conservative scenario, the cost reductions are greater and more rapid. The same is true for the advanced scenario compared with the mid scenario. Between scenarios there is a direct link between the deployed offshore wind capacity and the achieved cost reduction; therefore, an implicit link between that cost reduction and realized investments in enabling infrastructure required to develop projects (e.g., ports, vessels, and transmission). This is especially true for floating offshore wind energy as the industry begins to develop the first commercial-scale projects. In other words, global offshore wind deployment will not result in the United States. automatically achieving the cost trajectories reported in this study if the sector does not invest in the required infrastructure that could allow projects to be built more efficiently.

For the mid scenario, the total expected fixed-bottom CapEx learning reductions between 2025 and 2050 are 17.7%. For floating offshore wind energy between 2030 and 2035, the estimated CapEx reduction is 25%. Not only do the learning curves derived for floating offshore wind have a higher learning rate, but the projected deployment growth rate is more rapid, leading to a higher percentage of cost reduction relative to current costs.

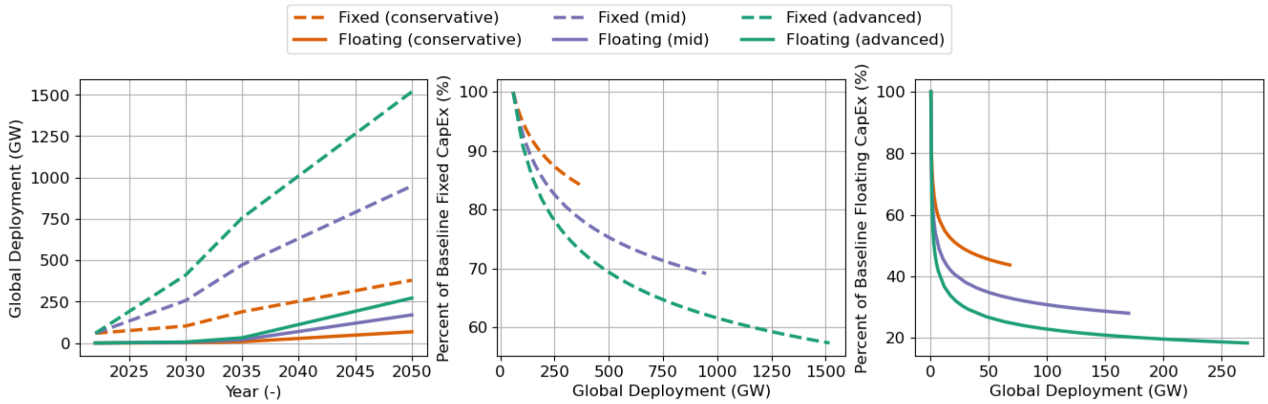

Figure 8. Global fixed-bottom and floating offshore wind deployment projections over time (left) and (right) percentage of baseline offshore wind project CapEx from industry learning under different scenarios relative to baseline values

6.7.3 Near-Term Cost Adjustments

The long-term cost trajectory of offshore wind energy is driven by the learning rate, which captures cost reductions from increased efficiency, learning by doing, technology innovations, and maturing supply chains. A corresponding learning curve also depends on an assumed deployment rate, where a higher rate accelerates the learning-by-doing aspect of cost reductions. These trajectories do not consider broader macroeconomic conditions (e.g., interest rates, inflation) or supply chain disruptions to commodity or labor prices (e.g., the Covid-19 pandemic, the Russia-Ukraine war). Offshore wind energy project developers have cited these factors as significant causes of increased project costs; therefore, the learning curve approach adopted in previous NREL studies (e.g., Beiter et al. [2020]; Shields et al. [2021b]; NREL [2022]; Duffy et al. [2022]; Musial et al. [2023a]) requires some adaptation to account for these ongoing price pressures. As a result, we imposed a short-term cost correction on top of an empirically derived learning curve to effectively adjust the early years of the cost trajectory.

It is important to note that these learning curves are applied to CapEx costs at the project level; in other words, they are not intended to capture overall project financing (which is separately evaluated by the choice of the FCR). Typically, broader economic drivers such as inflation or interest rates would not be considered within a CapEx learning curve. However, these factors (along with supply chain disruptions) impact technology providers as well as project developers, and we assume that these costs are, in some part, passed on to the project CapEx budget. Manufacturers—particularly for a growing U.S. supply chain—also need to finance the construction or expansion of new facilities, and so the cost of capital is a fundamental near-future cost driver. Therefore, the short-term adjustments to the learning curve are intended to reflect the economic pressures facing the supply chain (and passed on to project developers), not the financing of the offshore wind projects.

We define separate learning curves and cost corrections for the mid, conservative, and advanced cost scenarios to help demonstrate the uncertainty associated with future offshore wind energy costs; the subsequent range of cost values encompasses uncertainty in the determining the historical learning rate, the rate of future deployment, and the magnitude and persistence of short-term economic challenges. These cost corrections (Figure 9) are represented as percentage point increases to the baseline costs which are combined with the long-term cost projections (Figure 8).

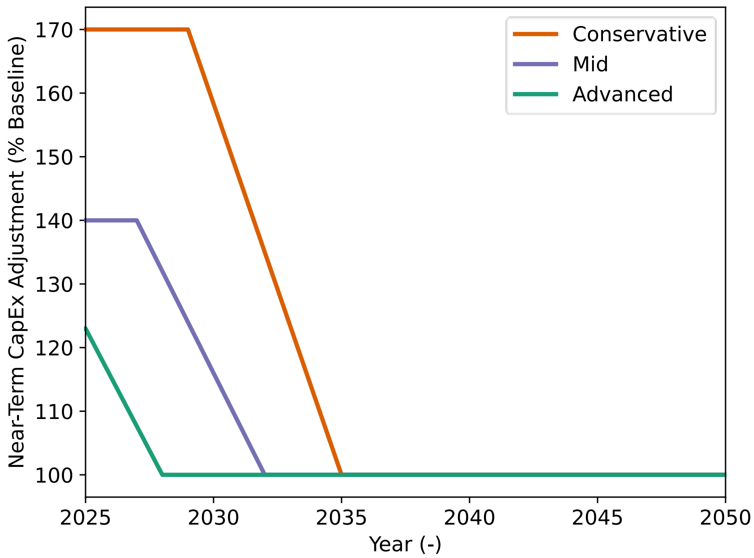

Figure 9. Cost corrections imposed on the learning curve to estimate impacts of macroeconomic conditions and supply chain disruptions on the near-term costs of offshore wind energy

Forecasting the impacts of macroeconomic conditions and supply chain disruptions to relevant offshore wind cost factors is beyond the scope of this study. We defined the assumptions underlying each scenario to provide several trajectories for how critical conditions could evolve over time. These assumptions dictate the magnitude of the short-term cost correction and the duration over which it is applied to the base learning curve.

The mid scenario imposes a 40% capital cost increase factor that remains constant until 2027 and phases out by 2032. This magnitude approximately matches industry-reported cost increases incurred between 2020 and 2023 (Penn, Reed, and Plumer 2023; Public Service Commission of the State of New York 2023). Since the end of 2022, steel prices have stabilized or decreased and the U.S. Federal Reserve has stabilized interest rates, as well as signaled that it may decrease rates as inflation starts to recede (Rugaber 2024). Simultaneously, the U.S. offshore wind energy industry has experienced some additional investment in the supply chain, such as the Qualifying Advanced Energy Project Credit (Section 48C of the Inflation Reduction Act) award made to Hellenic Cables to develop a cable manufacturing facility in Maryland (Office of Manufacturing and Energy Supply Chains 2024). Further investment, such as NYSERDA's intended $300 million major component manufacturing supply chain request for proposals (NYSERDA 2024b) suggesting that expected supply chain bottlenecks in the late 2020s may be somewhat alleviated. Finally, rapid action by states such as New York has allowed terminated projects to quickly reenter the pipeline, stabilizing the expected annual project deployment rate. The mid scenario assumes that these trends incrementally reduce financing rates, pipeline uncertainty, and inflationary capital cost pressures on projects with a COD after 2027—and likely a final investment decision around 2025—until the macroeconomic factors recede in 2030 and cost evolution over time is exclusively driven by the learning curve.

The conservative scenario assumes that the 40% cost increases from the mid scenario will grow to a higher value of 70%. This increase primarily reflects higher uncertainty in the deployment pipeline, which could drive financing costs higher than their current rates. This scenario could be manifested by additional projects terminating their offtake agreements, geopolitical disruptions, or deployment hesitation attributed to environmental or technology uncertainty. We further assume that these sector-specific challenges are exacerbated by persistently high federal interest rates that may not begin to come down until the late 2020s. It also assumes further delays in developing a U.S. supply chain, which would reduce the available components and increase project risk. As a result, the cost increase factor persists until 2029 and does not phase out until 2035.

The advanced scenario assumes that the average cost increase faced by the U.S. pipeline is closer to the lower bound estimate of 20% over 2021 costs estimated in the literature (Lloyd-Williams 2023). This scenario assumes an optimistic trajectory for developing a domestic supply chain (thereby reducing risk and cost to projects), inflation and interest rate decreases, and pipeline certainty. These assumptions reflect a strong overall U.S. economy, consistent political support for offshore wind, effective state and regional coordination, and effective implementation of the Inflation Reduction Act and other supportive policies to advance supply chain and project investments. As a result, the short-term cost corrections phase out by 2027.

As with any learning curve method, the goal of the analysis is not to explicitly model each unique cost reduction driver for a specific project, but to estimate the long-term trajectory of the offshore wind energy sector. In effect, the short-term cost corrections in the mid, conservative, and advanced scenarios adjust the starting point of the learning curve to reflect the cost uncertainty within the industry. Long-term cost projections, driven by learning curves that span ranges of learning rates and deployment trajectories, further encompass the uncertainty in the evolution of the industry. Some care should be taken when comparing individual data points (e.g., estimated all-in development costs from New York's 2023 offshore wind solicitation) with the broader industry trends captured by these cost trajectories. See Section 7.5.1 for a discussion of some of these differences.

7 Cost Results

In this section, we present our findings, shown separately for LCOE, CapEx, OpEx, and NCF. We show LCOE, CapEx, OpEx, and NCF results for 2025 (COD) for fixed-bottom only. We then show results for 2030 and 2035 for both fixed-bottom and floating wind energy across the entire United States. We discuss broad, national trends, and then more specific regional trends. Finally, we provide a more detailed look at the Northeast results for 2030 and 2035 to show how geographic trends within a region can impact LCOE.

We have detailed results for all regions and cost components, which are provided separately in an online map.[19] We also detail costs over time for two reference sites in Section 7.3 and conduct a sensitivity analysis on several LCOE drivers in Section 7.4. When referring to specific regions on the Atlantic coast, we assume the North Atlantic to represent the area north of Cape Cod, the South Atlantic to represent the area south of the mouth of the Chesapeake Bay, and the Central Atlantic to represent the area between.

7.1 Costs in 2025

We modeled baseline LCOE values in 2025 for a representative 1-GW fixed-bottom wind farm at each point offshore the United States, bordered by the Exclusive Economic Zone and 1,300-m water depth. The spatial cost trends (Figure 10) are largely consistent with those reported by Beiter et al. (2016). The lowest cost areas for fixed-bottom offshore wind project deployment (with water depths lower than 60 m) are primarily located in the North and Central Atlantic regions, with average fixed-bottom costs of around $175/MWh (conservative scenario), $140/MWh (mid scenario), and $110/MWh (advanced scenario). Fixed-bottom LCOE estimates in the Gulf of Mexico (average LCOE of $299/MWh, $233/MWh, and $186/MWh for the conservative, mid, and advanced scenarios, respectively) are higher than the East Coast primarily due to lower wind speeds in the region.

[19] https://bit.ly/oswlcoe

Figure 10. Fixed-bottom mid LCOE values [$/MWh] for the baseline year of 2025 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

Figure 11. Fixed-bottom mid CapEx values [$/kW] for the baseline year of 2025 in 2022 USD.

Notes: 1) CapEx values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

CapEx and OpEx generally follow trends of lower costs near the coastline with increasing costs away from the coastline due to longer POIs and distance from ports (Figure 11 and Figure 12). Although there is some spatial variation in costs for different locations, most fixed-bottom CapEx is greater than $6,000/kW, whereas all OpEx is higher than $83/kW-year in the mid scenario. There are a few sites closer to shore that have CapEx values less than $5,000/kW. In the conservative scenario, most sites have a CapEx that is greater than $7,750, whereas OpEx is higher than $89/kW-year. In the advanced scenario, most sites have a CapEx higher than $4,800, and an OpEx higher than $79/kW-yr. We set map legend bins to provide more resolution in 2030 and 2035. As a result, the maps show reasonably consistent values in the highest cost bin throughout the domain.

Figure 12. Fixed-bottom mid OpEx values [$/kW-yr] for the baseline year of 2025 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

NCF also shows variation on a regional scale, with the highest NCF values (> 45%) existing in the Central to Northern Atlantic regions where there is a better wind resource (Figure 13). The Gulf of Mexico and the South Atlantic region have some of the lowest NCF values (less than 35%). The NCF values tend to decrease in the Gulf of Mexico from east to west, as well as offshore the East Coast from north to south.

Figure 13. Fixed-bottom net capacity factor values (percent) for the baseline year of 2025.

Note: BOEM lease and planning areas as of March 2024.

7.1.1 Atlantic

In 2025, North Atlantic fixed-bottom sites have a mean LCOE of $182/MWh (conservative), $141/MWh (mid), and $113/MWh (advanced) in the North Atlantic region. The average LCOE estimated in the Central Atlantic region is $135/MWh in 2025 in the mid scenario, whereas the average LCOE in the South Atlantic region is nearly $166/MWh.

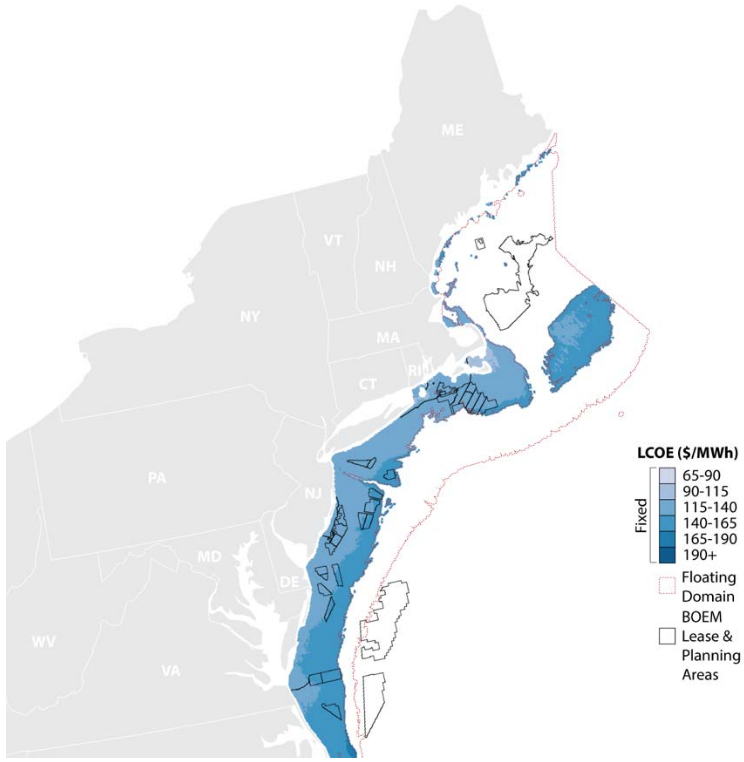

Figure 14. Fixed-bottom North Atlantic LCOE values [$/MWh] for the baseline year 2025 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection; 2) BOEM lease and planning areas as of March 2024.

LCOE tends to increase as projects move farther from shore, which is driven by longer export cable routes and greater distances to marshaling and O&M ports. Furthermore, water depth tends to increase as distance from shore increases, requiring larger and more expensive foundations (Beiter et al. 2016). Finally, wind speeds are not consistent along the entire coastline, leading to slightly lower capacity factors off the coasts of New York and New Jersey relative to New England.

The LCOE results for fixed-bottom offshore wind energy projects in the North and Central Atlantic regions are driven by the following trends in CapEx, OpEx, and NCF:

- Mean CapEx values range between $8,093/kW (conservative), $6,260 /kW (mid), and $5,055/kW (advanced scenario). These values vary significantly throughout the spatial domain.
- CapEx increases rapidly as projects get further from shore for regions with water depths below 60 m because of the relatively steep slopes (and subsequent increase in foundation costs).
- OpEx values are less sensitive to water depth and wind speed and are primarily driven by the distance from the operations port to the project site. Mean OpEx values for fixed-

bottom plants are roughly $90/kW-yr (conservative), $85/kW-yr (mid), and $80/kW-yr (advanced).

- NCF values tend to be higher in northern regions by Massachusetts (greater than 45%) and decrease slightly toward the Central Atlantic (40%–45%).

7.1.2 Gulf of Mexico

In the Gulf of Mexico, LCOE values for fixed-bottom projects generally increase farther from shore but also increase from the western side of the Gulf, which has a better wind resource, toward the eastern side of the Gulf, which has a relatively lower wind resource. The average 2025 fixed-bottom LCOE estimated in the Gulf of Mexico is $299/MWh, $233/MWh, and $186/MWh for the conservative, mid, and advanced scenarios, respectively.

The ports and POIs that were assumed for this study are spread generally evenly along the coast of the Gulf of Mexico, making the primary drivers of LCOE to be technology (floating or fixed), which depends on water depth and distance from shore (export cable length and distance to port).

The LCOE results for offshore wind energy projects in the Gulf of Mexico are driven by the following trends in CapEx, OpEx, and NCF:

- Average CapEx of around $6,500/kW (mid scenario) in 2025 in water depths that are likely to use fixed-bottom substructures. These values include cost adders for the additional design considerations to locate offshore wind turbines in a hurricane-prone environment, including higher insurance premiums and more robust substructures and towers.

- Average OpEx costs for fixed-bottom projects of around $84/kW-yr (mid scenario).

- The wind resource in the Gulf of Mexico generally increases from east to west (Figure 13). Although not the only factor driving LCOE, this trend causes the LCOE values to decrease from east to west. The highest NCF values in the west reach 40%–45% near Corpus Christi, Texas, with values less than 35% for the rest of the gulf.

7.2 Costs in 2030 and 2035

LCOE declines from 2025 to 2030 for fixed-bottom sites and continues to decline from 2030 to 2035 for both floating and fixed-bottom sites. (Figures 15 and 16). For a detailed description of how the cost projections were developed, see Section 6.7. Compared to the 2025 baseline values (Figure 11), LCOE values at fixed-bottom sites in 2030 are around 23% lower across the nation in the mid scenario (Figure 15). In the conservative scenario, the average national fixed-bottom costs fall by around 8%, whereas in the advanced scenario they decrease by 30%. The absolute magnitude of reduction in cost over time is not the same across sites because of spatial variability in physical parameters like water depths, distance to infrastructure, and wind resources. However, relative improvements to CapEx, OpEx, and NCF are consistent for all sites.

In 2030, we continue to see the lowest fixed-bottom LCOE in the North and Central Atlantic regions. Minimum LCOE in those regions is around $85/MWh in the mid scenario ($130/MWh in the conservative scenario; $63/MWh in the advanced scenario), whereas the average across the entire region remains above $100/MWh. The West Coast, North Atlantic, and Central Atlantic regions have floating sites with LCOE just above $150/MWh ($230/MWh in the conservative scenario; $100/MWh in the advanced scenario). Most sites, however, are more expensive, with a combined West Coast, Central, and North Atlantic floating average around $360/MWh in the mid scenario ($490/MWh in the conservative scenario; $270/MWh in the advanced scenario).

Figure 15. National LCOE [$/MWh] for 2030 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

In 2035, LCOE values are further reduced. We continue to see the lowest LCOE values for fixed-bottom sites in the Northeast. Nationally, fixed-bottom sites were on average 21% lower than 2030 LCOE values and nearly 40% lower than 2025 values in the mid scenario. In the conservative scenario, there were reductions of 37% between 2030 and 2035, resulting in a total average reduction of 42% between 2035 and 2025. In the advanced scenario, there were reductions of 11% between 2030 and 2035, resulting in an average reduction of 37% between 2035 and 2025.

Mid scenario floating LCOE values in some areas drop below $100 MWh, including parts of the Northeast, southern Oregon, northern California, and in Hawai'i. Floating site LCOE, across the nation, was on average 32% lower than 2030 values in the mid scenario. In the conservative scenario, floating site LCOE across the country was reduced by an average of 38%. In the advanced scenario, floating site LCOE across the country was reduced by an average of 29%. We see the largest relative reductions in the conservative scenario because the impacts of the near-term cost increase decline rapidly and significantly between 2030 and 2035 (see Figure 9).

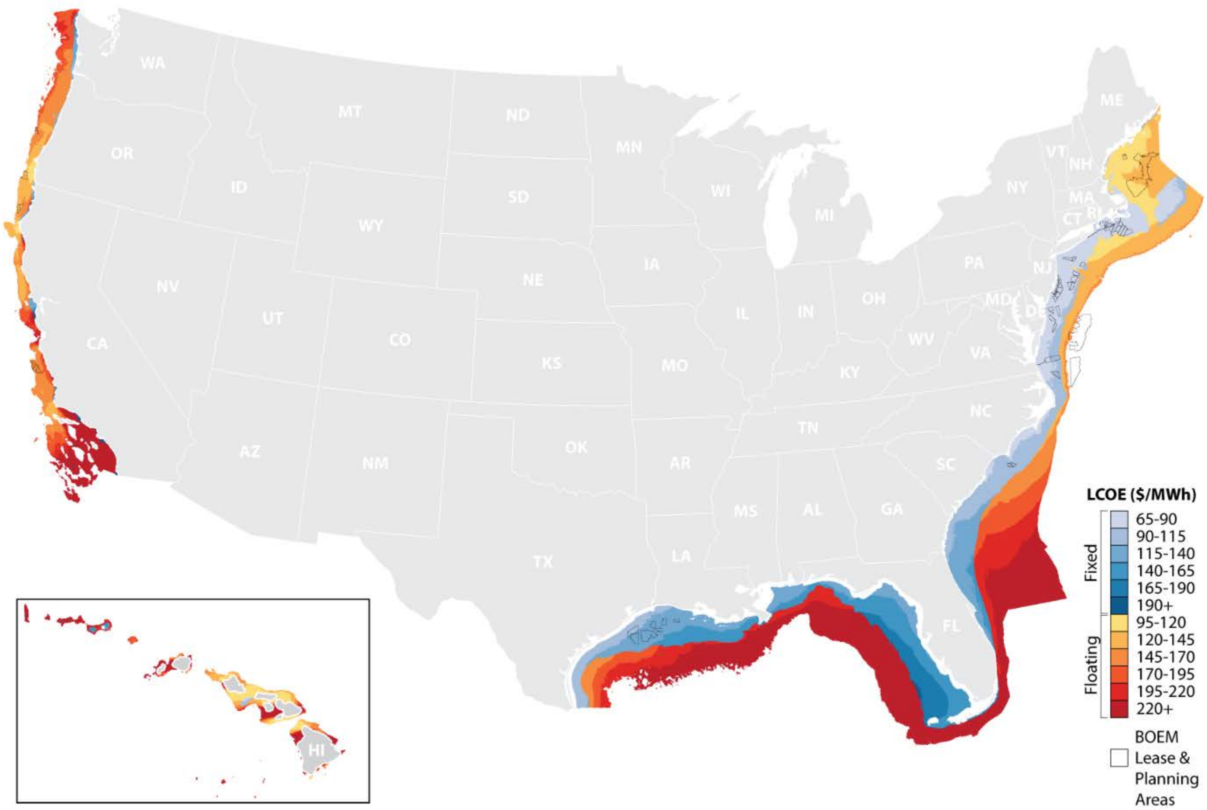

Figure 16. National LCOE [$/MWh] for 2035 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

By 2035, CapEx across the country has experienced significant reductions relative to 2025 for fixed-bottom and 2030 for floating (see Figure 18). Average fixed-bottom CapEx across the nation in 2035 is 42% lower than in 2025 in the mid scenario. In the conservative scenario, it is 47% lower than 2025, whereas in the advanced scenario it is 39% lower than 2025. Floating sites across the country see an average CapEx reduction of 33% between 2030 and 2035 in the mid scenario. In the conservative scenario, this reduction changes to 39%, whereas in the advanced scenario the reduction is 30%. Like LCOE reductions, we see the largest reductions to CapEx in the conservative scenario due to rapid decline of the near-term cost increases between 2030 and 2035 (see Figure 9). In the advanced scenario, reductions between 2030 and 2035 in CapEx are due to the learning curve only, whereas in the mid scenario, both the learning curve and lessening impacts of the near-term cost increases play a role in CapEx reductions. Low CapEx values, like in earlier years, continue to be found nearer to installation ports and in lower water depths.

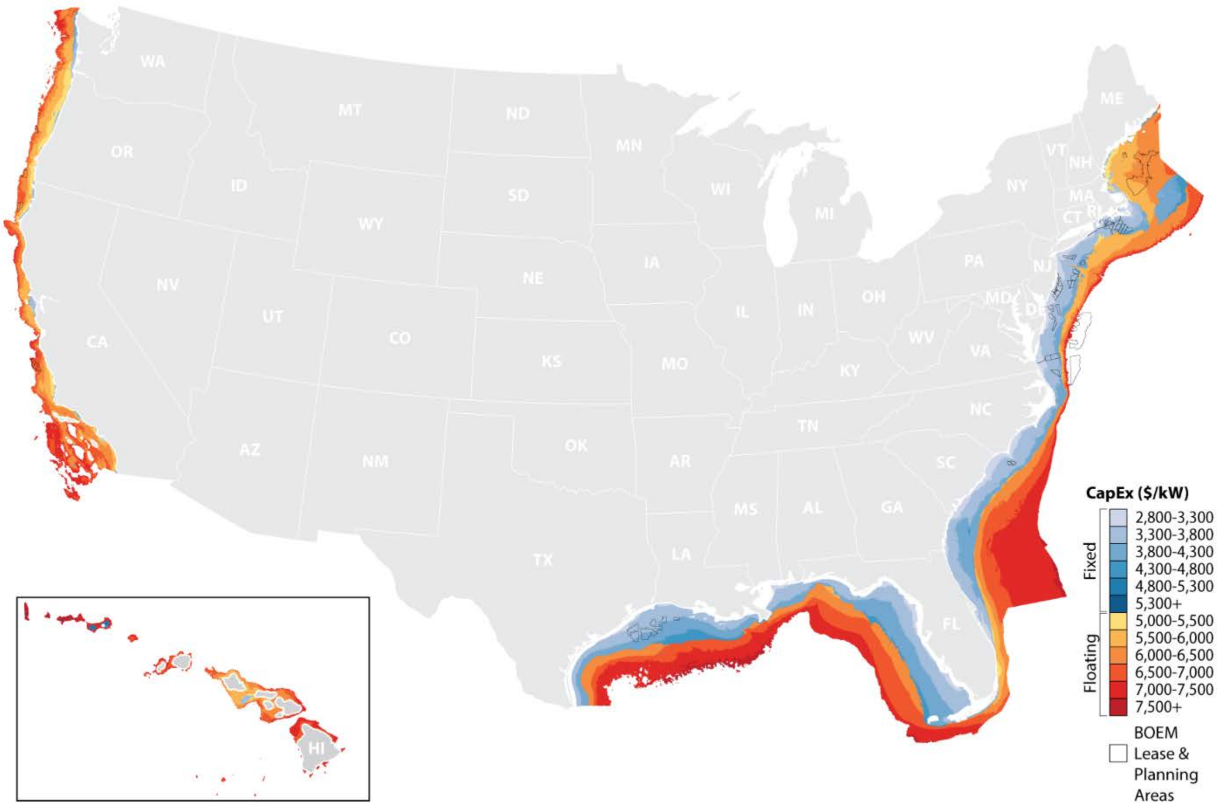

Figure 17. National CapEx [$/kW] for 2035 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

OpEx costs for both fixed-bottom and floating also experience reductions by 2035 (see Figure 18). For fixed-bottom sites, we see an average reduction of 11% in 2035 from 2025, and 6% from 2030 in the mid scenario. In the conservative scenario, 2035 OpEx values are 4% lower than 2030, and 6% lower than 2025, whereas in the advanced scenario, reductions are 8% and 14% from 2030 and 2025, respectively. On the other hand, floating sites have an average reduction of 7%, 6%, and 8% from 2030 in the mid, conservative, and advanced scenarios, respectively. For floating sites especially, where OpEx is more variable due to increased impact of distance to port, we see OpEx increasing as distance to O&M port increases.

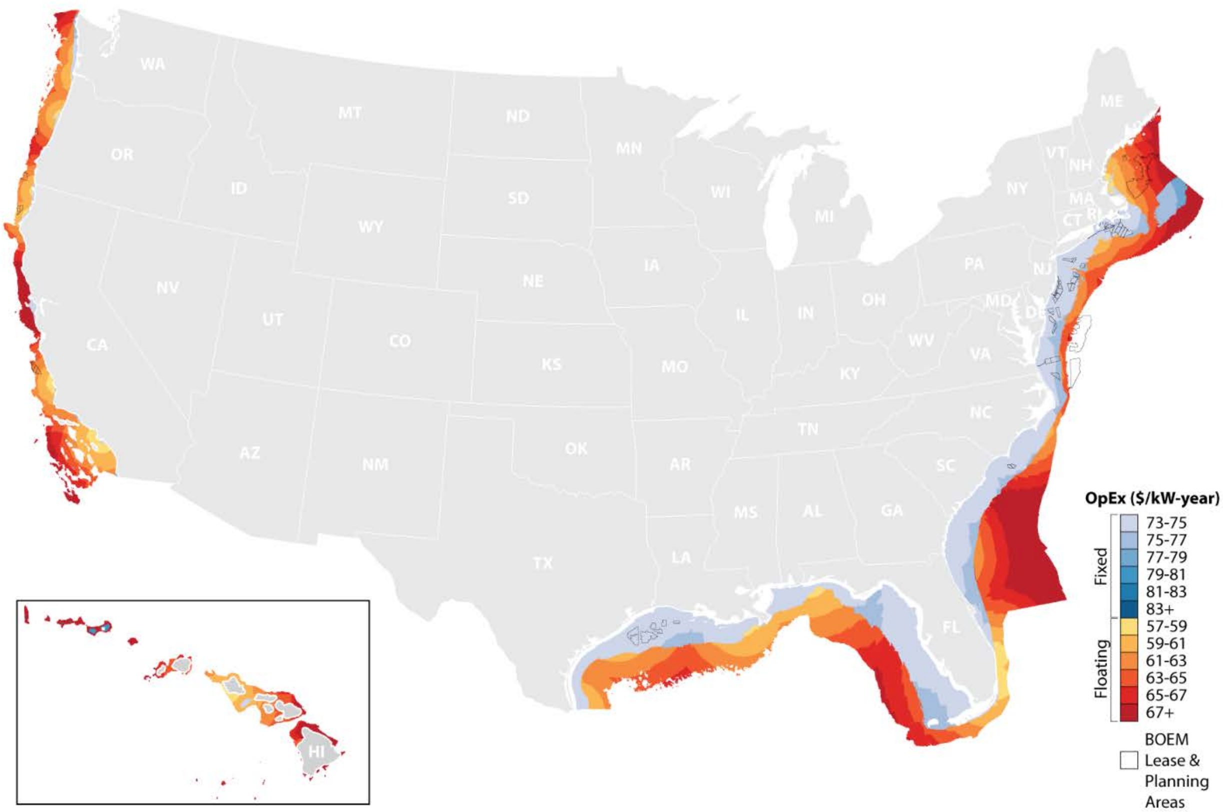

Figure 18. National OpEx [$/kW-yr] for 2035 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

Average fixed-bottom NCF in 2035 is higher than 2025 by 3% in the mid scenario, whereas average floating NCF is higher than 2030 values by 1%. In the conservative scenario, average fixed-bottom NCF increases by 1% from 2025, whereas floating increases by less than 1% from 2030. In the advanced scenario, these increases are 5% and 2% for fixed-bottom (from 2025) and floating (from 2030). We applied the same NCF increases over time to both fixed-bottom and floating wind energy.

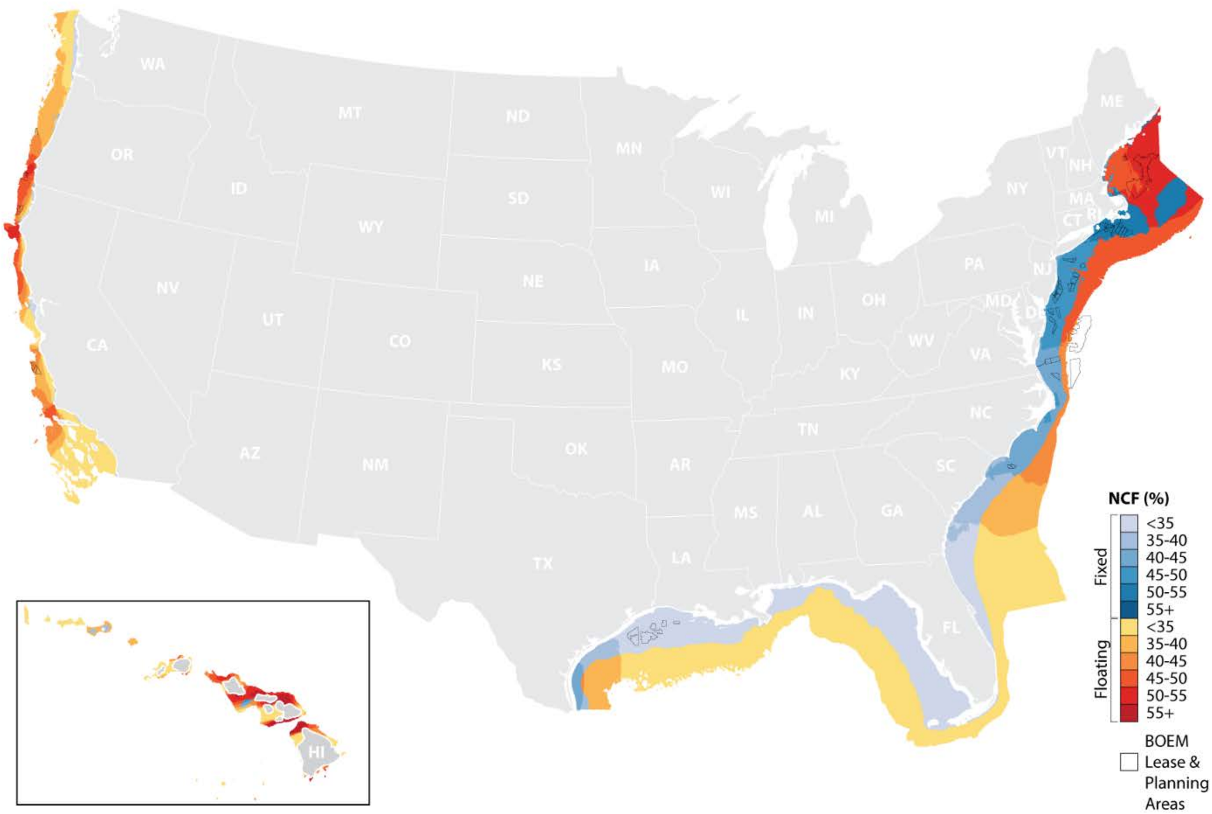

Figure 19. National NCF (%) for 2035 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

7.2.1 West Coast and Hawai`i

The deep waters off the West Coast will require floating wind turbines. Southern California shows higher LCOE values (above $220/MWh for the mid scenario in 2035), due to low wind resource (see Figure 16 and Figure 19). LCOE generally decreases moving northward toward the San Francisco Bay Area but then increases briefly before decreasing again until Southern Oregon. LCOE begins to increase again in central Oregon moving northward to Washington. Given that CapEx is similar on a north-to-south gradient, the LCOE is highly dependent on the wind resource and resulting NCF (see Figure 20). Indeed, the West Coast has some of the highest net capacity factors in the country, with pockets in Northern California and Southern Oregon reaching nearly 53% in the mid scenario (50% in the conservative scenario, and 55% in the advanced scenario). As a result, we see floating LCOE in those pockets around $125/MWh in 2035 in the mid scenario ($180/MWh in the conservative scenario; $88/MWh in the advanced scenario).

Like the West Coast, the waters surrounding Hawai`i are also typically deep. Some nearshore areas with depths less than 60 m are unlikely to be developed due to their proximity to shore and the subsequent impact on ocean users. Much of Hawai`i's waters are deeper than 1,300 m, greatly reducing developable floating sites. Again, like the West Coast, NCF is the largest determining factor for Hawai`i LCOE values, with large variation in NCF across the islands. The highest NCF is found between the big island and Maui, as well as between Maui and Oahu, with values above 55% in the mid scenario. Subsequently, the lowest LCOE values are found there, with values below $100/MWh in the mid, conservative, and advanced scenarios.

The LCOE results for floating offshore wind projects on the West Coast and Hawai`i are driven by the following trends in CapEx, OpEx, and NCF:

- Capital costs are primarily impacted by deep waters and the limited interconnection infrastructure on the West Coast, which can lead to long export cable routes and high costs. Distance to port facilities can impact installation costs and varying water depths can impact mooring system costs. These trends are discussed in more detail in Beiter et al. (2020).

- CapEx in Hawai`i is also affected by distance to POIs, which are primarily concentrated in the Honolulu region. As a result, proximity to the southern region of O`ahu is a primary cost driver. As an added benefit, the Kalealoa/Barber's Point Harbor is located on the south side of O`ahu and could be developed for floating wind activities.

- The steep seafloor slopes off the West Coast and surrounding some Hawaiian Islands indicate a relatively short linear distance from shore to the 1,300-m isobath, which is the external boundary for this cost study. As a result, the spatial extent of the West Coast domain is narrower than the East Coast.

- OpEx can vary significantly along the West Coast because of limited access to ports without air-draft restrictions. Unlike CapEx, where the component costs are the most significant cost driver, transit distance is one of the primary drivers for OpEx. As a result, OpEx is higher near the San Francisco Bay area (because wind turbines cannot be towed under the Golden Gate Bridge). Regions closer to ports without air-draft restrictions tend to have lower OpEx costs.

- The highest annual mean wind speeds on the West Coast are found offshore southern Oregon and northern California. The NCF values are also therefore highest in this region (> 50%). The NCF values are particularly low in southern California (well under 20%), which drives the LCOE values up.

7.2.2 Gulf of Mexico

The LCOE for fixed-bottom wind energy in the Gulf of Mexico declined from an average across all sites of $230/MWh in 2025 to $140/MWh in 2035 in the mid scenario ($299/MWh to $170/MWh in the conservative scenario; $186/MWh to $116/MWh in the advanced scenario). The lowest LCOE values are found in the western Gulf nearest to Texas, due to the stronger wind resource, with 2035 LCOE values under $100/MWh in the mid scenario ($110 in the conservative scenario, and $75/MWh in the advanced scenario).

The estimated LCOE of floating wind plants in the Gulf of Mexico is estimated to be generally more expensive than on the West Coast. Floating sites are generally farther from shore in a large part to the more extensive shallow shelf in the Gulf, which does not exist on the West Coast, resulting in longer export cable lengths. Like fixed-bottom wind energy, the lowest floating LCOE is found in the western Gulf with values just above $150/MWh in the mid scenario ($225/MWh in the conservative; $110/MWh in the advanced scenario) in 2035.

7.2.3 Atlantic

Both fixed-bottom and floating sites on the Atlantic coast see large reductions in cost by 2030 and 2035. Although most of the development activity in the Atlantic has been focused on fixed-bottom offshore wind, floating wind also presents a viable opportunity for the region. There are large areas in which floating wind LCOE values are among the lowest in the country, with values below $100/MWh. By 2035, many fixed-bottom sites in the Central and North Atlantic regions are well below $75/MWh in the mid scenario (below $100/MWh in the conservative; below $65/MWh in the advanced). We provide more detailed analysis on the Northeast regions LCOE, CapEx, OpEx, and NCF in 2030 and 2035 in the following sections.

7.2.3.1 LCOE

Taking a closer look at the North Atlantic region, we see a reduction in fixed-bottom LCOE from 2025 average values of around $140/MWh to around $110/MWh in 2030 to $85/MWh 2035 in the mid scenario (Figure 21 and Figure 22). This nearly 40% reduction in LCOE over 10 years is a result of moving forward along the learning curve as well as the easing near-term cost pressures. In the conservative scenario, LCOE values in 2035 experience a more than 40% reduction relative to 2025, with most of that reduction occurring between 2030 and 2035 as the near-term cost increases erode. On the other hand, in the advanced scenario, most of the reductions between 2025 and 2035 occur between 2025 and 2030, with average LCOE values around $113/MWh in 2025, $80/MWh in 2030, and $70/MWh in 2035. The Central Atlantic region LCOE reductions follow a similar path, although average values are slightly lower than North Atlantic sites.

Floating site LCOE in the North Atlantic region in 2035 is, on average, around $120/MWh, compared to $175/MWh in 2030 in the mid scenario, amounting to a reduction by over 30% in the 5 years. In the conservative scenario, the reduction is closer to 40%, with 2035 average LCOE values near to $170/MWh, and 2030 values near $275/MWh. In the advanced scenario, reductions are less than 30% between 2030 and 2035, moving from an average LCOE of $118/MWh to $84/MWh. Floating sites in the Central Atlantic, are on average, around 7% higher than the North Atlantic sites for all scenarios.

Although the advanced scenario has a higher learning rate than both the mid and conservative scenarios, the lessening of the near-term cost impacts has an outsized impact in the conservative scenario but plays no role in the advanced scenario between 2030 and 2035. The relative LCOE reductions for floating in the 5 years between 2030 and 2035 are nearly as great as those for fixed-bottom wind energy in the 10 years between 2025 and 2035.

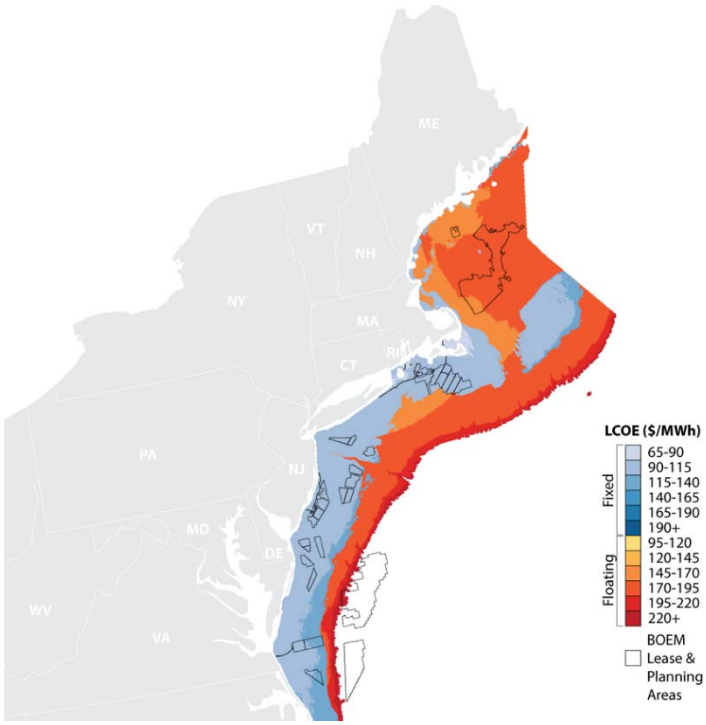

Figure 20. North Atlantic LCOE [$/MWh] in year 2030 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

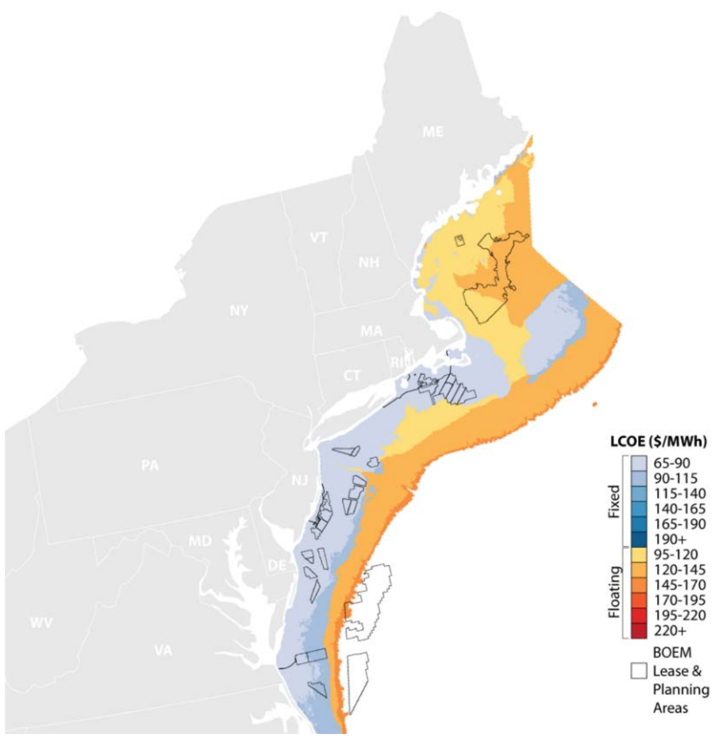

Figure 21. North Atlantic LCOE [$/MWh] for year 2035 in 2022 USD.

Notes: 1) LCOE values are calculated at the point of interconnection. 2) BOEM lease and planning areas as of March 2024.

7.2.3.2 CapEx

The reductions for LCOE mentioned earlier are largely driven by reductions in CapEx due to both the movement along the learning curve and the near-term cost adjustment eroding. In the mid scenario, average North Atlantic fixed-bottom CapEx is around $5,150/kW in 2030 (see Figure 22), and just below $4,000/kW in 2035 (see Figure 23). CapEx in 2035 is therefore around 40% less than 2025, and 23% less than 2030 in the mid scenario.

For floating sites in the North Atlantic, CapEx in 2035 is over 30% lower than 2030, with average values around $9,000/kW and $6,000/kW in 2030 and 2035, respectively. In the mid scenario in 2035, we see minimum CapEx values close to $3,000/kW and near $5,200 in the North Atlantic for fixed-bottom and floating wind energy, respectively.

As discussed in Section 7.2.3.1, the largest 5-year period of relative reductions occurs for fixed-bottom and floating sites in the conservative scenario between 2030 and 2035 with reductions of around 40%. In the conservative scenario, CapEx values are as low as $3,600/kW and $7,500/kW for fixed-bottom and floating wind energy, respectively. In the advanced scenario, the reduction between 2030 and 2035 is nearly 10% for fixed bottom and 30% for floating. Unlike the conservative scenario, reductions in CapEx between 2030 and 2035 occur due to movement along the learning curve.

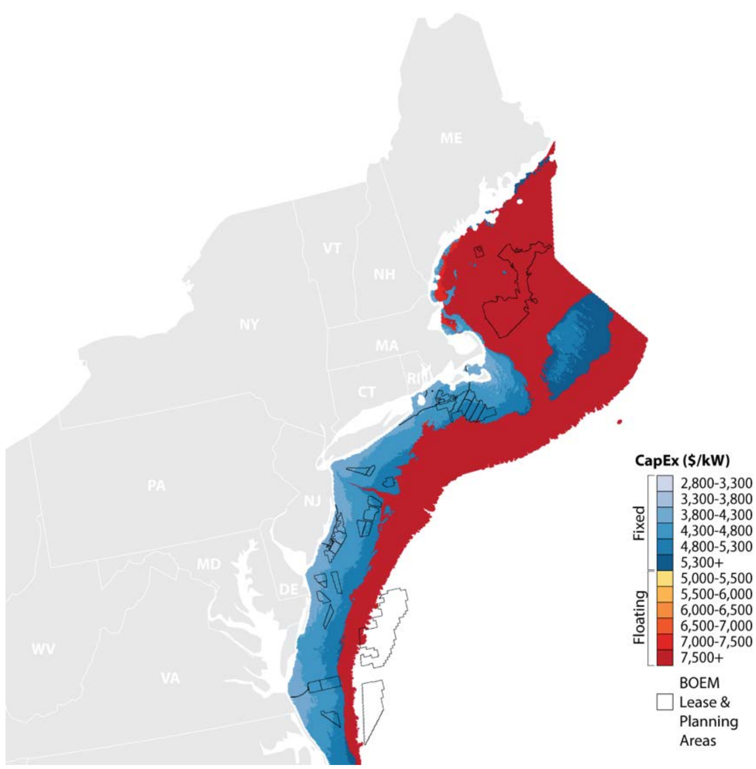

Figure 22. North Atlantic CapEx [$/kW] for year 2030 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

By 2035, reductions in CapEx reveal the greater spatial variability on the lower end of values for both fixed and floating wind areas (Figure 23). Sites closer to shore become less expensive than sites farther from shore. This contrast is caused by an increase in the distance to the assembly and installation port, as well as by longer export cables and greater water depths.

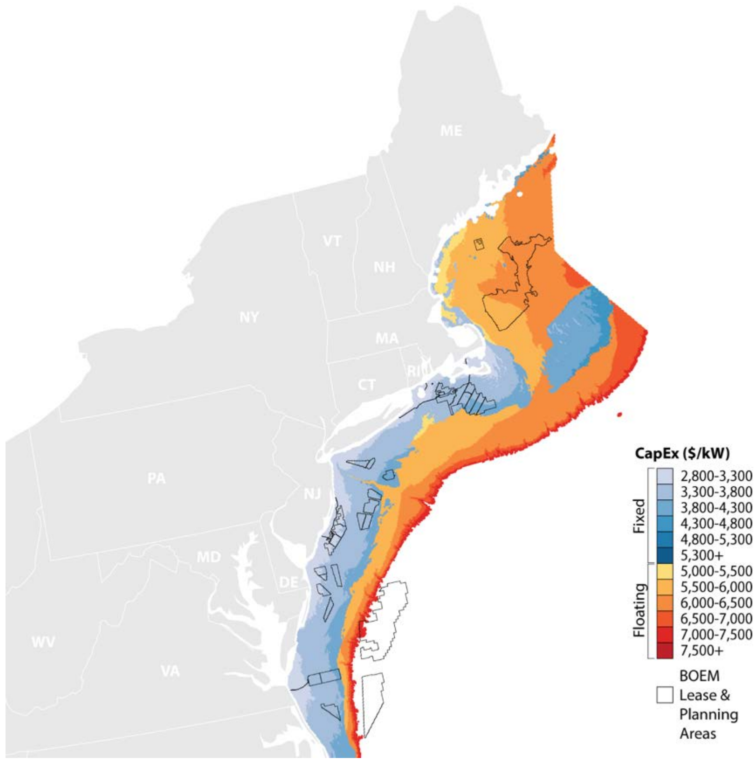

Figure 23. North Atlantic CapEx [$/kW] for year 2035 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

7.2.3.3 Operational Expenditures

OpEx reductions also contributed to lowering LCOE values, though not as significantly as CapEx reductions. For fixed-bottom wind power plants, average OpEx values in the North Atlantic decreased to around $90/kW-yr (conservative), $80/kW-yr (mid, Figure 24), and $75/kW-yr (advanced) in 2030, and further to around $86/kW-yr (conservative), $75/kW-yr (mid, Figure 25), and $69/kW-yr (advanced) in 2035.

For floating wind power plants, average North Atlantic OpEx values were around $77/kW-yr (conservative), $69/kW-yr (mid, Figure 24), $63/kW-yr (advanced) in 2030, and decreased to around $72/kW-yr (conservative), $64/kW-yr (mid, Figure 25), $58/kW-yr (advanced) in 2035.

In general, wave heights and wind speeds tend to increase farther from shore, which can increase the cost of O&M activities due to weather downtime. The Central Atlantic sites had similar (<5% difference) OpEx values to the North Atlantic sites across both technologies and all scenarios. Unlike with CapEx, the largest relative OpEx reductions occurred in the advanced scenario between 2030 and 2035 for floating and between 2025 and 2035 for fixed-bottom wind energy.

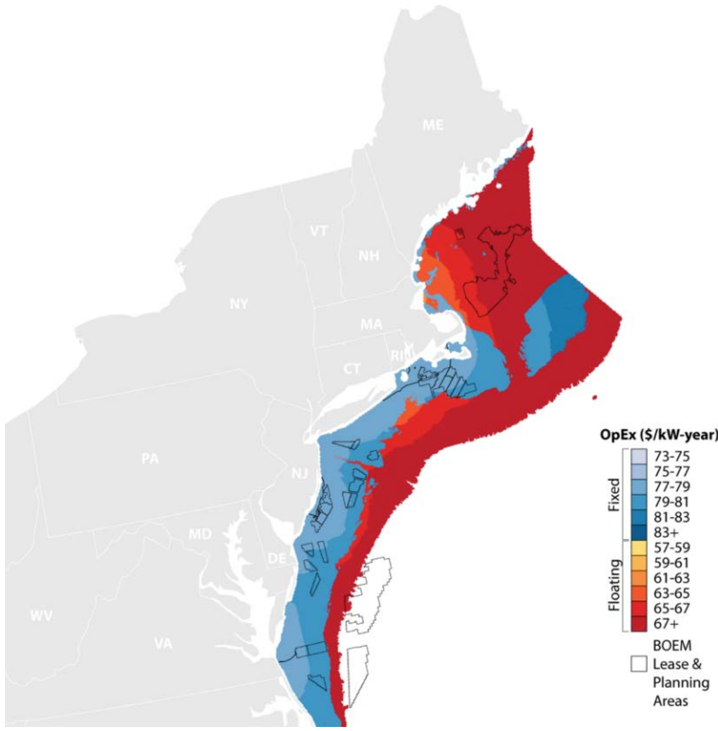

Figure 24. North Atlantic OpEx [$/kW-yr] for year 2030 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

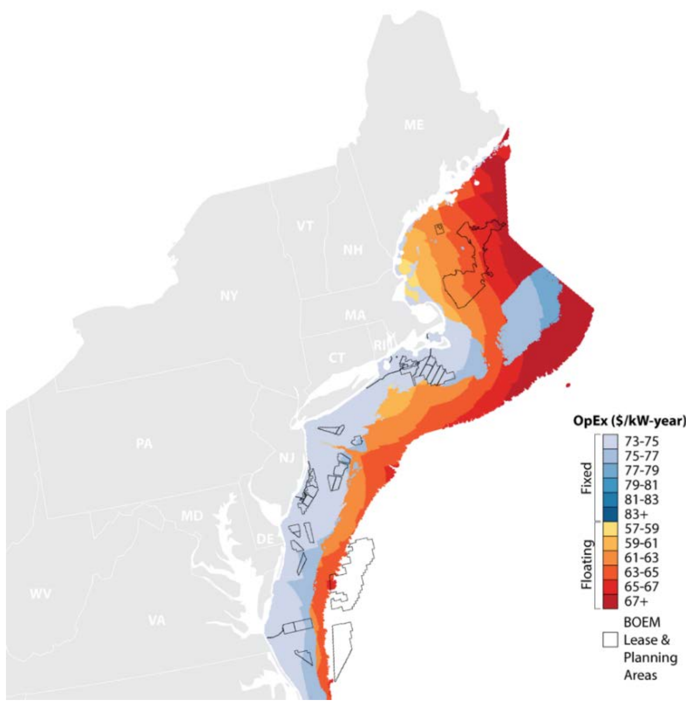

Figure 25. North Atlantic OpEx [$/kW-yr] for year 2035 in 2022 USD.

Note: BOEM lease and planning areas as of March 2024.

7.2.3.4 Net Capacity Factor

NCF has a large impact on LCOE, and even small improvements can lead to reductions in LCOE (Eq. 1). The North Atlantic region (particularly the sites farther from shore) have some of the best wind resources in the country. In 2030, NCF values in the North Atlantic region range between 45% and 55% in the mid scenario (Figure 26). Those values increase in 2035 (Figure 27), with more sites above 50%, but do not reach 55%. In the conservative scenario, average North Atlantic NCF for both technologies is around 48% in 2030 and 2035, whereas it is around 52% in 2030 and 53% in 2035 in the advanced scenario. The Central Atlantic NCF, for fixed-bottom and floating wind energy, is around 5% lower than North Atlantic values for both types in all scenarios.

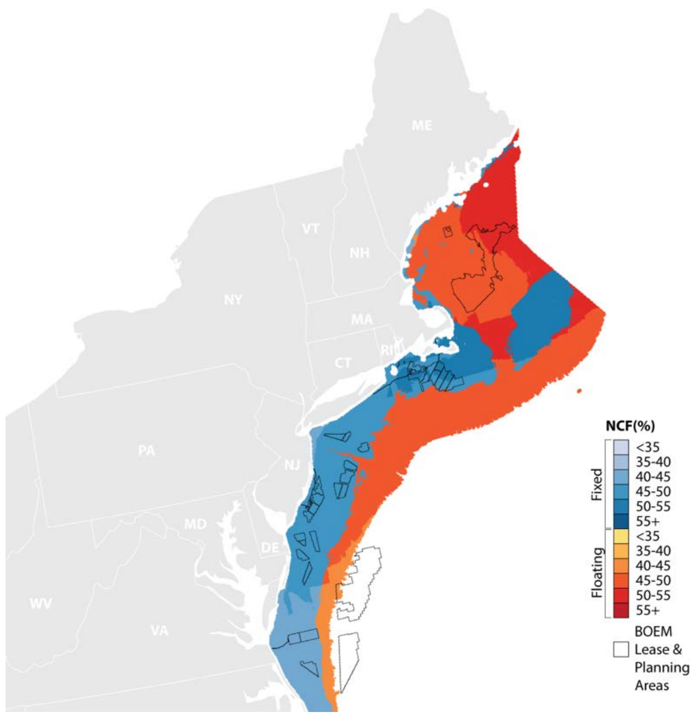

Figure 26. Net capacity factor (percent) for the North Atlantic region for 2030.

Note: BOEM lease and planning areas as of March 2024.

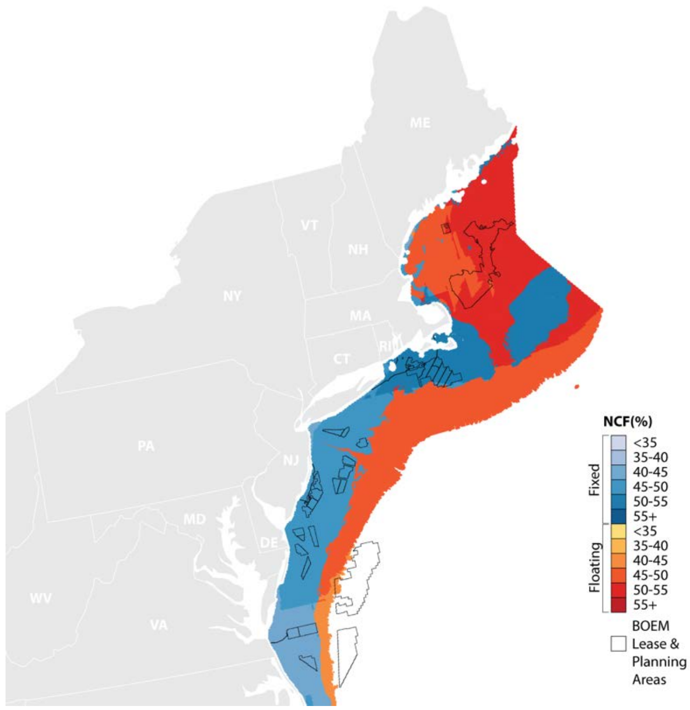

Figure 27. Net capacity factor (percent) for the North Atlantic region for 2035.

Note: BOEM lease and planning areas as of March 2024.

7.3 Cost Summary at Selected Sites

To summarize how cost changes over time, we defined two reference sites: one offshore the West Coast (offshore northern California) and one in the New York Bight. For these sites, we present time series of LCOE, CapEx, OpEx, and NCF estimates (Figures 28−31). We select these reference sites to illustrate possible costs for floating and fixed-bottom projects. The West Coast site indicates projected costs of floating wind plants, and the New York Bight site provides indicative projected costs for a fixed-bottom wind plant. Floating offshore wind energy costs are presented from 2030 when the first commercial-scale floating offshore wind projects might feasibly be constructed in the United States.

7.3.1 Levelized Cost of Energy

LCOE is typically higher for the floating project offshore the West Coast than the fixed-bottom project in the New York Bight (Figure 28) region. In 2025, under the mid scenario, we estimate LCOE values of roughly $129/MWh for the fixed-bottom location. In 2030, these values fall to $100/MWh for the fixed-bottom site and $198/MWh for the floating site. By 2035, the floating costs drop to around $195/MWh, $136/MWh, and $95/MWh for the conservative, mid, and advanced scenarios, respectively. The fixed-bottom New York Bight costs drop to $90/MWh, $72/MWh, and $57/MWh in 2050 for the conservative, mid, and advanced scenarios, respectively. Floating estimates in 2050 are $149/MWh, $95/MWh, and $62/MWh for the scenarios, respectively. Cost reduction trajectories are not smooth because the underlying deployment assumptions (Figure 8 [left]) and CapEx adjustments (Figure 9) have discrete changes in slope. We note the potential for floating wind costs to drop below the fixed-bottom costs in the advanced scenario, which would likely correspond to a significant investment in enabling infrastructure, technology development, and standardization for the floating wind energy industry.

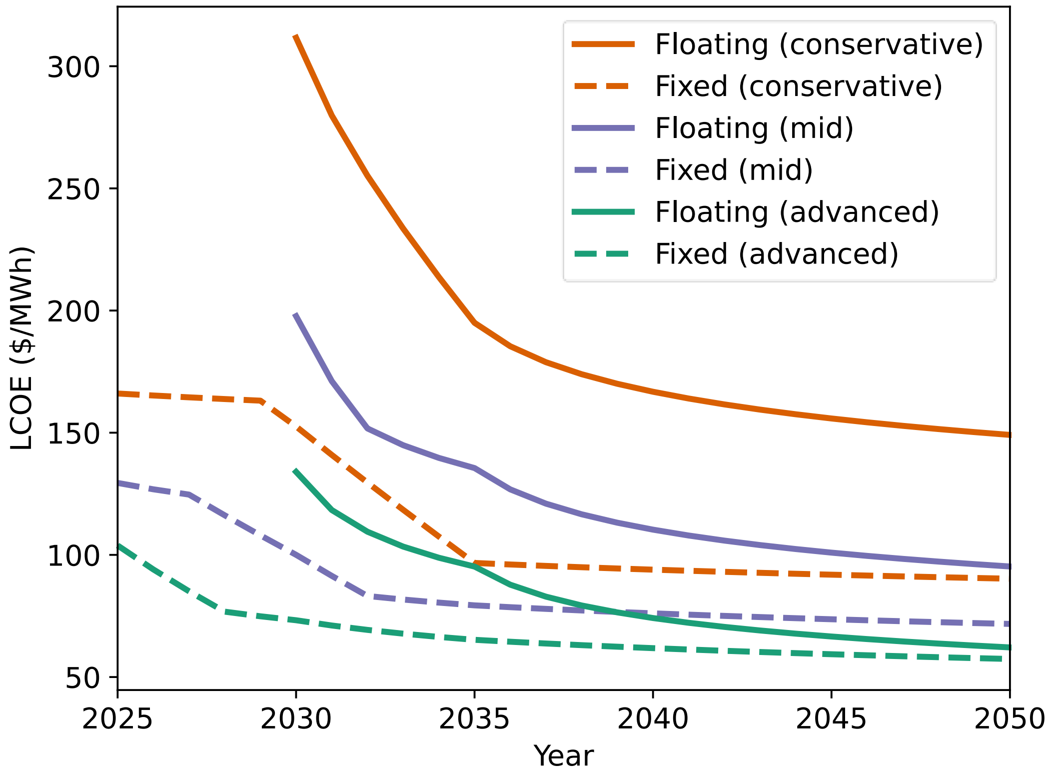

Figure 28. LCOE ($/MWh) for reference fixed-bottom and floating offshore wind energy projects.

Note: LCOE values are calculated at the point of interconnection.

7.3.2 Capital Expenditures

Figure 29 illustrates how CapEx values evolve over time at the reference sites under three scenarios. The 2025 CapEx values for the fixed-bottom reference project are estimated to be $5,809 (ranging from $4,691/kW in the advanced scenario to $7,510/kW in the conservative scenario). The 2030 mid scenario fixed and floating project CapEx values are $4,399/kW and $8,845/kW, respectively. As global deployment expands rapidly, floating projects experience a considerable drop in CapEx such that by 2035, the CapEx values range from approximately $8,445/kW (conservative), $5,956/kW (mid), and $4,276/kW (advanced). In 2035, the fixed-bottom CapEx costs are roughly between $2,892/kW and $4,014/kW across the three scenarios. Cost reduction trajectories are not smooth because the underlying deployment assumptions (Figure 8 [left]) and CapEx adjustments (Figure 9) have discrete changes in slope.

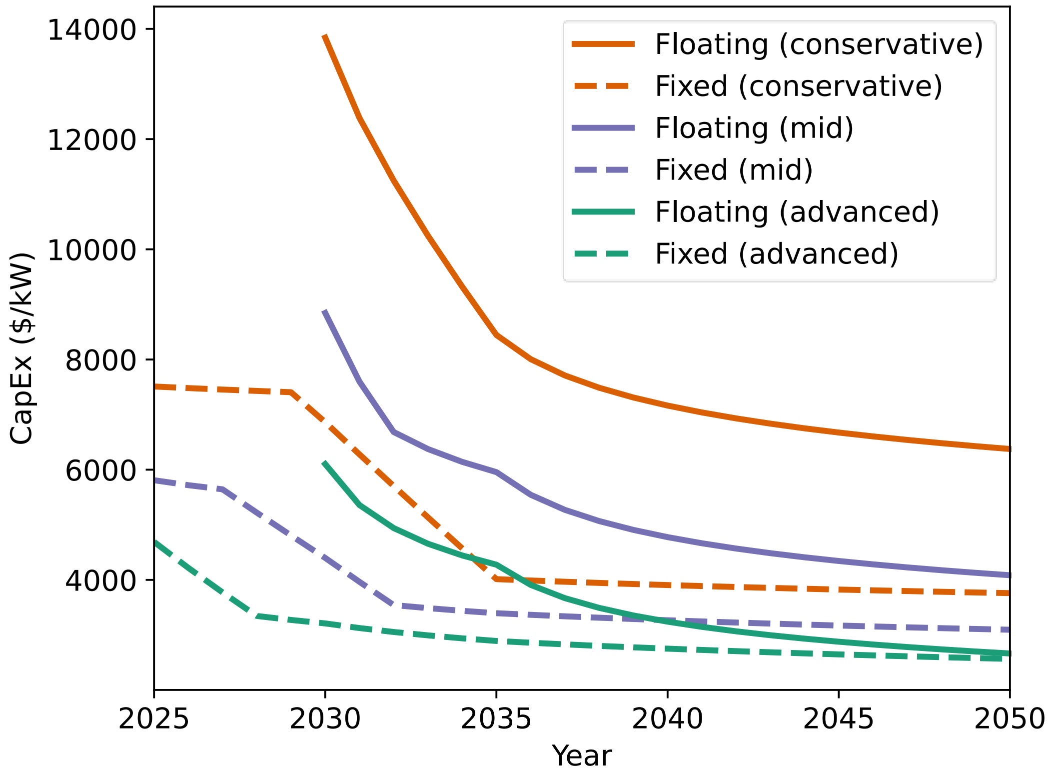

Figure 29. CapEx ($/MW) for reference fixed-bottom and floating offshore wind energy sites

7.3.3 Operational Expenditures

Compared to LCOE and CapEx, OpEx values for floating projects follow a different trend in that they are less expensive than their fixed-bottom counterparts. Figure 30 shows the projected evolution in OpEx over time by scenario for the two reference sites. In 2025 under the mid scenario, OpEx start out at $84/kW-yr for the fixed-bottom site. By 2035, the fixed-bottom OpEx costs are roughly $85/kW-yr (conservative), $74/kW-yr (mid), and $68/kW-yr (advanced). The floating costs in 2035 are $67/kW-yr (conservative), $60/kW-yr (mid), and $55/kW-yr (advanced). In modeling baseline OpEx, we assume that floating projects are able to attain lower costs with a tow-to-port maintenance strategy for major repairs. Since fixed-bottom O&M activities require expensive wind turbine installation vessels for major repairs or component replacement, we estimate lower OpEx for floating wind plants (which require only the use of tugs to transport the wind turbine back to the port). Although in-port repairs of floating wind turbines require more extensive port facilities than on-site repair, we estimate the additional port costs to contribute less to the total OpEx than the higher vessel costs for on-site repair using wind turbine installation vessels. Some uncertainty around the comparison of OpEx fixed and floating costs exists, due to a possibility that infrastructure necessary for floating wind turbines (e.g., suspended cables, moorings, floating substations) will require more frequent O&M activities, resulting in higher recurring O&M costs. Distance from the site to the O&M port is a driving factor in OpEx costs, but so is wave height (Section 6.4).

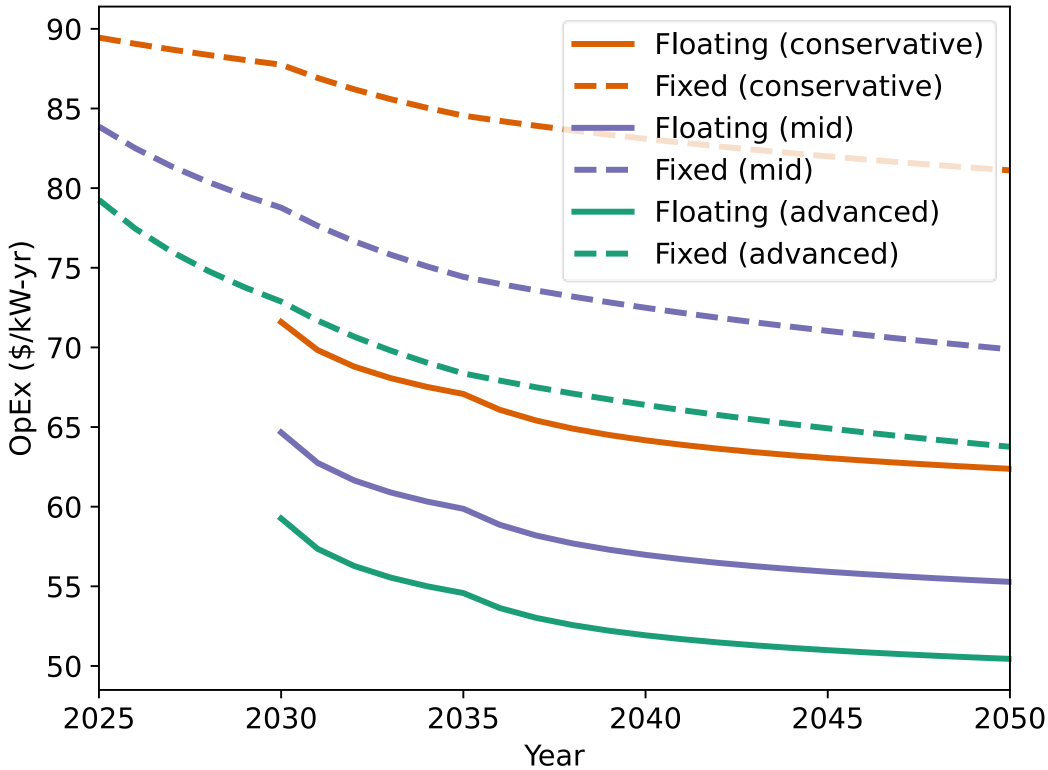

Figure 30. OpEx ($/kW-yr) for representative fixed-bottom and floating offshore wind energy projects

7.3.4 Net Capacity Factor

Using NCF as a metric, we investigate wind plant performance given our assumption that performance will increase over time (Section 4.4) for the two sites (Figure 31) due to innovation and experience. Given the same wind resource, performance is primarily driven by the specific power of the selected wind turbines. Specific power is the ratio of a turbine's rated power to rotor expressed in terms of $W/m.^2$ For instance, Fleming et al. (2023) demonstrate that novel wind plant control strategies (such as wake steering) may improve annual energy production by as much as 1.3%–2.3%, even after optimizing the wind plant layout.

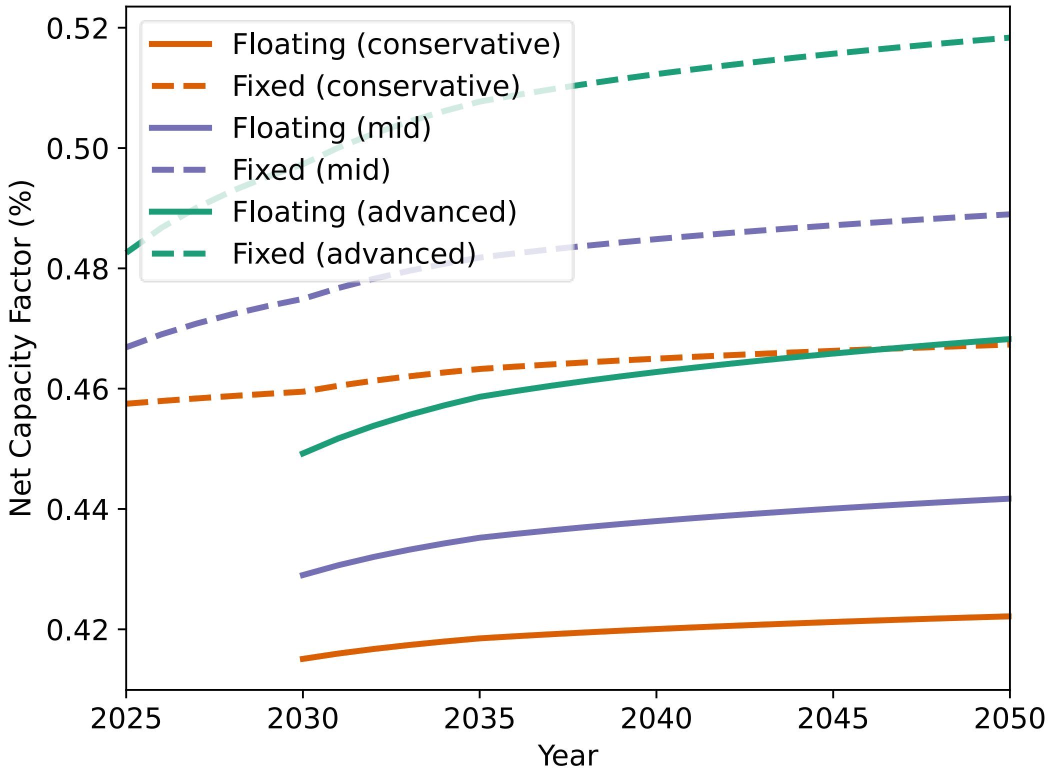

Figure 31. Net capacity factor (%) for reference fixed-bottom and floating offshore wind sites

Wind-turbine-specific power has a significant impact on a plant's performance trajectory over time, whereas the wind resource drives regional variation in the magnitude of the overall offshore wind plant performance. In this case, the wind resource is better at the fixed site, such that the 2030 NCF value is 47% compared to the roughly 43% at the floating site under the mid scenario. By 2035, the NCF is assumed to reach around 51% (advanced), 48% (mid), and 46% (conservative) for the fixed-bottom site. At the floating reference site, we estimate net capacity factors to be around 46%, 44%, and 42% in the advanced, mid, and conservative scenarios, respectively.

7.4 LCOE Sensitivity

In Figure 32 we explore the sensitivity of LCOE to changes in intermediate cost line items at the reference sites described earlier. We specifically identified wind turbine CapEx, substructure CapEx, export cable CapEx, and grid connection CapEx as the line items that either comprise a significant portion of the total CapEx, have the potential to vary significantly by site, or both. We illustrate the sensitivity of LCOE to changes in these parameters including impacts to soft costs like construction insurance, which are calculated as a function of the wind turbine CapEx and balance-of-system costs. These parameters are varied +/- 25% in increments of 1%, and the resulting change in LCOE is computed for COD 2035. Additionally, to address both uncertainty in the debt interest rate (Section 6.5) and plant performance, we include the FCR and NCF in the sensitivity analysis. Note that a 2% change in the debt rate yields a more than 8% relative change in nominal FCR compared to the assumed value of 7.67%. This process is repeated for a fixed-bottom site (Figure 32) and a floating site (Figure 33).

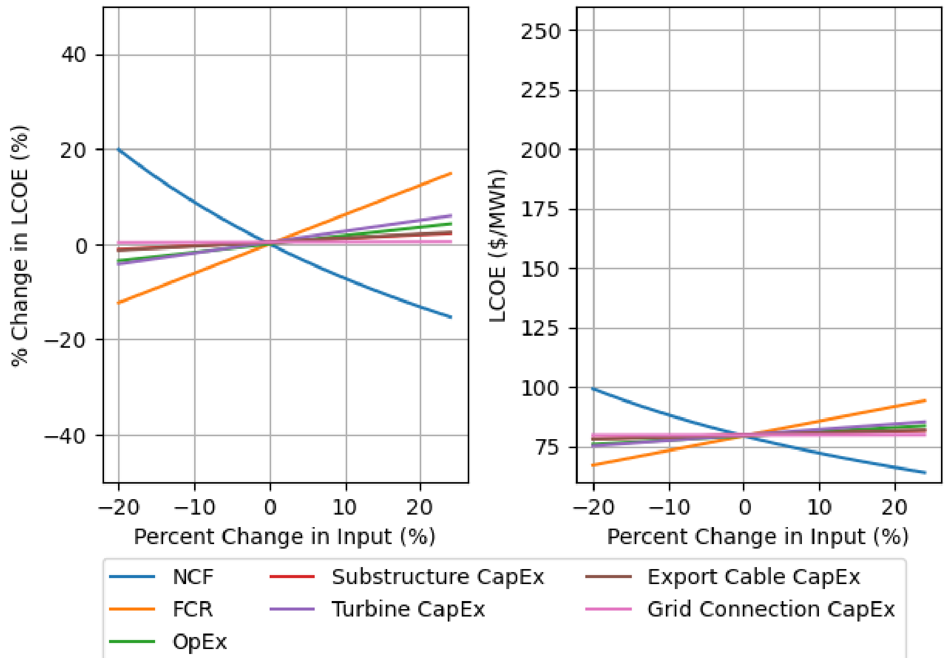

Figure 32. Sensitivity analysis for a fixed-bottom site

Note: LCOE values are calculated at the point of interconnection.

The fixed-bottom offshore wind LCOE at this site is most sensitive to NCF, followed closely by FCR (Figure 32). Among CapEx line items, LCOE is most sensitive to a variation in wind turbine CapEx and export cable CapEx at this site.

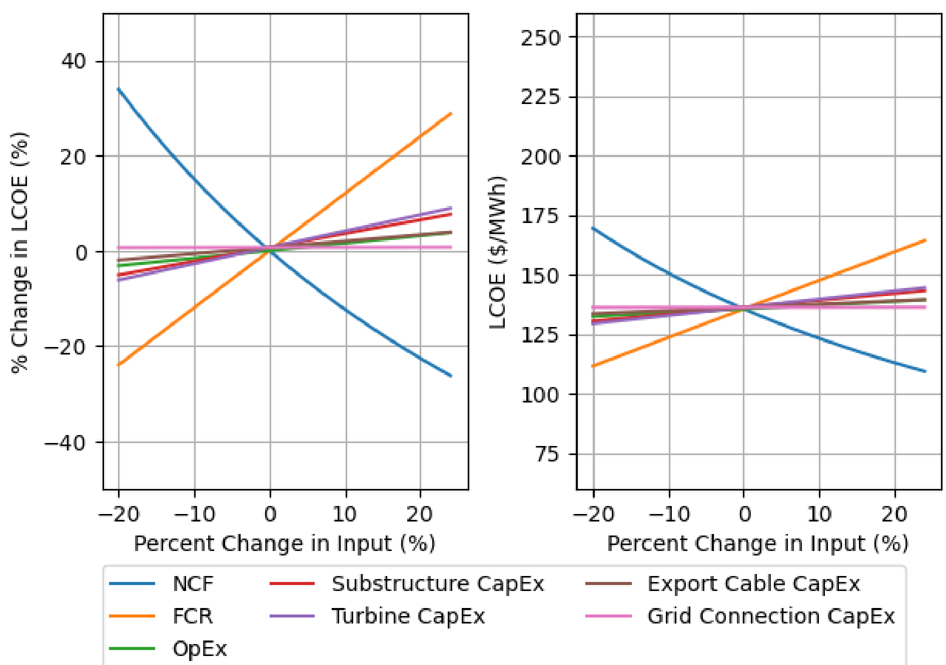

Figure 33. Sensitivity analysis for a floating site

Note: LCOE values are calculated at the point of interconnection.

Floating offshore wind LCOE at this site is most sensitive to NCF, then FCR (or the debt interest rate) (Figure 34). Among CapEx line items, LCOE is most sensitive to variation in wind turbine CapEx and substructure CapEx at this site.

7.5 Comparison to Other Cost Estimates

7.5.1 Previous NREL Studies

Prior regional cost studies show spatial variation in cost[20] within each region that is attributed to different factors. For example, Beiter et al. (2016) conducted a first-of-its-kind spatial-economic cost reduction pathway analysis and estimated that the LCOE of reference 600-MW fixed-bottom and floating offshore wind projects could decrease between 2015 and 2030 from $231/MWh to $116/MWh and $267/MWh to $111/MWh, respectively. In California, Beiter et al. (2020) analyzed a spatial domain within a 40- to 1,300-m water depth and assumed 1-GW plant sizes and 8-MW (2019) and 15-MW (2032) wind turbines. That study found an LCOE range of $95−$207/MWh for a COD in 2019. For a COD in 2019−2032, the LCOE declined by an average of 44%, for a range of $61−$74/MWh. Another study indicated one of the main challenges to establishing wind power plants offshore California was deep water, which reduces the usable area and total generating capacity of the lease area, as well as limits the availability of bulk transmission access and ports (Cooperman et al. 2022). In Oregon, a range of LCOE was found to be between $63 and $87/MWh for a COD of 2032 (Musial et al. 2019). That study assumed a 600-MW wind plant with semisubmersible floating substructures and 6-, 10-, 12-, and 15-MW turbines for a COD of 2019, 2022, 2027, and 2032, respectively. In Hawaii, the LCOE of a 600-MW floating offshore wind plant with 15-MW wind turbines was estimated to average roughly $69−$81/MWh with a 2032 COD (Shields et al. 2021b). In the Gulf of Mexico, LCOE values for a COD ranged from $88–$213/MWh for a 600-MW plant with 10-MW turbines and jacket substructures fixed to the ocean floor (Musial et al. 2020). Finally, NREL publishes fixed-bottom and floating offshore wind cost results in the Annual Technology Baseline (NREL 2023) and the *Offshore Wind Market Report* (Musial et al. 2023b). The latter report calculates an average fixed-bottom offshore wind LCOE of $63/MWh and a range of floating offshore wind LCOE between $66 and $128/MWh by 2030.

The results presented in this report typically estimate higher costs than those previous studies. The increase in fixed-bottom project costs is primarily driven by the recent economic challenges that have impacted the industry (Section 6.2 and Section 6.7.3). Although we estimate that these effects will persist in the 2020s, the LCOE trajectories in this report typically return to the range of cost estimates presented in Musial et al. (2023b) by the mid-2030s. Floating wind cost estimates presented in this report remain two to three times higher throughout the 2030s than the findings from previous studies. Earlier reports from Musial et al. (2019, 2020), Beiter et al. (2020), and Shields et al. (2021b) assume that a mature supply chain is available for the modeled projects whereas this report presents the transition from a precommercial to a commercial industry. This transition will involve constructing staging and integration ports, industrializing key technologies, and developing a robust supply chain, which may require tens of billions of dollars of investment on the U.S. West Coast (Shields et al. 2023b). Furthermore, Shields et al. (2023b) estimate that it could take 8–16 years to plan, permit, and construct installation or

[20] For comparison all costs presented in this section have been inflated to 2022 U.S. dollars from their reported dollar-years using the consumer price index.

manufacturing port sites on the West Coast. Many of the cost reductions embedded within the learning curve will require the port infrastructure to be in place before they can be fully realized. For example, floating wind developers will likely have to demonstrate that they can build commercial-scale projects on schedule to reduce capital and financing costs, requiring experience with port logistics, at-sea activities, and component manufacturing and assembly. Some of this experience could be obtained in the global market, but much of it will have to come from projects in the United States.

The floating wind LCOE trajectories presented in Figure 25 indicate a 10- to 15-year period of rapid cost reduction followed by a more gradual reduction through 2050. The first period corresponds to growing global (and some U.S.) deployment coupled with gradual easing of the economic challenges of the mid-2020s. The second period corresponds to ongoing learning by doing and approximately reflects a time frame that occurs after key enabling infrastructure has been constructed. These trajectories indicate that the industry could approach LCOE values closer to those reported in previous studies (under $100/MWh) in the 2040s if sufficient progress is made to develop critical port and supply chain assets.

7.5.2 Reported Costs From Renegotiated Projects

In February 2024, NYSERDA announced the winners of the fourth New York offshore wind solicitation round (NY4), which was designed as a part of the state's response to macroeconomic and inflationary challenges. Empire Wind 1 and Sunrise Wind were the provisional winners with a reported all-in development cost of $150.15/MWh and operational dates in 2026. In contrast, we estimated a range of unsubsidized costs between $94.6 and $164.1/MWh in the region in 2026. Although the full project financing details are not public, it is reasonable to assume that the NY4 cost estimates incorporate the effects of the ITC and/or other federal and state incentive mechanisms, which would potentially push the unsubsidized cost well above $150.15/MWh. At first glance, there could be a disagreement between the unsubsidized NREL and NY4 cost estimates.

It is challenging to compare costs (or prices) between different projects without conducting a detailed accounting of the underlying technology, cost, performance, subsidy, and financing assumptions (Beiter et al. 2021). Comparative studies adjust reported LCOE values for as many of these parameters as possible (Musial et al. 2023b). Conducting a direct comparison between the NREL and NY4 cost estimates is difficult—and perhaps misleading—for the following key reasons in bold.

The costs presented in this report are intended to capture broad spatial and temporal trends, and not to model specific project costs.

By design, NREL derived cost curves that are simple, accurate across regional or national scales, and computationally efficient; however, they do not have the precision of site-specific models used by project developers. NREL's models may underpredict costs at one site and overpredict costs at another. As discussed in Section 6, we have validated our underlying cost assumptions against industry data and published literature values and feel that they broadly reflect industry trends.

It is still useful to understand the potential sources of uncertainty between the NREL and NY4 cost estimates. Several key drivers may include:

- NREL uses the NOW-23 wind resource dataset that was likely not available to the Empire Wind 1 and Sunrise Wind projects as they developed their NY4 bids. NOW-23 estimates fairly high hub height wind speeds of over 9.5 meters per second in the project locations.
- NREL export system costs do not include onshore substation upgrades, as described in Beiter et al. (2020). We also do not capture the additional electrical infrastructure needed to make projects mesh-ready (as required in the NY4 solicitation).
- NREL's adoption of the FCR is a simplified model of real project financing and may not fully capture the perceived risk associated with renegotiated offshore wind energy projects.
- NREL's models assume a mature U.S. supply chain and do not account for transportation costs of major components such as monopiles, which could add significant premiums to component values for near-term projects.

The NY4 solicitation included additional cost commitments that are not conventionally captured in the LCOE.

The NY4 solicitation included provisions for expanded community benefit agreements and wildlife monitoring that will require developers to pay additional tens of millions of dollars to the state. Furthermore, the projects will invest over $400 million in supply chain, port, and transmission upgrades in New York. In principle, LCOE does not include a developer's commitments to supply chain, infrastructure, workforce, or community benefits because these are typically not project-specific costs, and it is not clear how these investments are amortized over multiple projects in a developer's portfolio. In practice, some of these costs will likely be passed on to the customer in the form of higher strike prices. As a result, it is reasonable to assume that the reported NY4 prices include some effects from additional cost structures not considered within typical LCOE modeling frameworks.

Developers are likely motivated to be conservative with their renegotiated bid prices to reduce the risk of future project cancellations.

The NY4 solicitation came at a historically unprecedented time in the U.S. offshore wind energy industry wherein the ultimate winners (Empire Wind 1 and Beacon Wind) had terminated their original offtake agreements less than 6 months prior to rebidding in the new round. In the wake of the economic upheaval surrounding the global offshore wind pipeline and the impairments, sunk costs, termination fees, and adverse publicity accrued by project developers, it is likely that the new bids were conservatively priced to more effectively hedge against future economic conditions.

Ultimately, the cost results presented in this report are built on cost curves that are designed to reflect industry-average trends over a 25-year time horizon. As with any average dataset, it is impossible to infer the overall accuracy by comparing with a single data point. The NY4 awards are an important indicator of the steps that the sector is taking to adjust to recent economic challenges, and it is encouraging to see that the reported costs (albeit likely subsidized) fall within the range of costs we estimate for the New York region in the mid-2020s. However, we encourage the reader to be cautious when comparing the results in this study with reported costs from specific projects, and instead to focus on the broad spatial and temporal trends (and the underlying cost drivers) that we present.

8 Summary and Conclusions

The offshore wind energy industry has demonstrated significant progress in the United States in the last several years as the first commercial-scale projects have been completed, over 10 GW of additional projects have received permitting approvals, states have coordinated on supply chain and procurement activities, and significant federal grants have been awarded to support building offshore wind infrastructure. At the same time, economywide challenges such as increasing commodity prices, inflation, and interest rates, exacerbated by sector-specific constraints such as a global lack of installation vessels, have led to higher LCOE. As a result, project developers have attempted to renegotiate their offtake agreements with state utilities or regulators and, in many cases, have had to terminate these contracts because they no longer considered their projects to be economically viable at the originally agreed-upon offtake price.

In this report, we present estimates of the LCOE for fixed-bottom offshore wind energy throughout major coastal regions of the United States between 2025 and 2050 and floating offshore wind energy between 2030 and 2050. The results include updates to technology, cost, wind resource, deployment, and financing parameters used in previous offshore wind cost studies conducted by NREL. The LCOE varies spatially based on wind resource, water depth, proximity to key infrastructure, and technology choice. We project costs to 2050 based on a learning curve that indicates long-term cost reductions, with adjustments in the near term to account for economic challenges and supply chain disruptions. The cost trajectories for floating offshore wind energy also incorporate impacts from the transition to a mature industry, and realizing forecasted cost reductions by specific years depends heavily on the rate of floating offshore wind energy deployment growth. We present conservative, mid, and advanced cost scenarios to reflect the uncertainty in future costs based on how the industry could evolve over the coming decades.

The results in this report reiterate some key findings from previous studies. The lowest-cost areas for fixed-bottom wind energy tend to be concentrated in the North and Central Atlantic regions, where wind speeds are strong and enabling infrastructure (such as ports and points of interconnection to the grid) are relatively close. Our reference site in these regions has a mean LCOE of around $129/MWh in 2025 in the mid scenario (with values of $104/MWh and $166/MWh in the advanced and conservative scenarios, respectively). We estimate that these costs could decrease by around 40% by 2035 as the economic challenges of the 2020s subside and increasing deployment drives down costs through experiential learning and industrialization.

The lowest-cost areas for floating wind energy are in the northern California/southern Oregon and Gulf of Maine regions primarily because they offer some of the best wind resources in the country. Projects built in the early 2030s would have to contend with immature technologies and suboptimal ports in addition to the economic challenges facing the fixed-bottom wind industry. A representative project in the northern California region could cost around $198/MWh in 2030, but these costs could decline rapidly by 32% in 2035 and 52% in 2050 as the supply chain matures and deployment increases (these values correspond to the mid scenario). The cost reduction potential by 2050 in the advanced scenario could be nearly 69% compared to the 2030 mid scenario LCOE if the enabling infrastructure and regulatory environment develop soon enough to allow faster deployment.

LCOE is not the only factor that decision makers will consider when evaluating the future role of offshore wind energy in the United States. Other factors, such as the opportunity to create manufacturing jobs, revitalize ports, or invest in disadvantaged communities could increase the value proposition of offshore wind. Decision makers can use the results from this report to better understand a range of future cost trajectories for offshore wind energy in their regions and to consider how LCOE and other factors could influence the role of the technology in their future renewable energy development plans.

9 Caveats

We suggest that the spatial and temporal trends of our model results be considered in more depth than the absolute values, given the uncertainty associated with near-term cost increases and learning curve values. It is impossible to validate the learning curve with observations because the learning curve predicts how well the industry will develop in the future. However, we are confident that costs should decline as the supply chain and industry develop more efficient methods. It is important to note that investment decisions by industry rely on some degree of certainty that their investments will result in a positive return, and we would argue that support from both the federal and state government is crucial in backing this certainty. For example, strong investment in port and points of interconnection infrastructure must be made before costs can decline. This and other important considerations are outlined here:

- Due to current transient market conditions and cost increases, there is a higher degree of uncertainty in estimating the baseline costs and the cost reductions we calculate for future years. Cost reductions are driven by how efficiently the industry and supply chain will develop in the near term and farther into the future to 2050. The sensitivity of costs to the learning curve (Section 7.4) highly depends on the pace at which the supply chain develops, which is influenced by a wide range of factors including global demand, wind turbine upscaling, energy and ocean policy, and numerous macroeconomic factors.
- The benefits of turbine upscaling must be weighed against the benefits of industrialization and standardization, which were demonstrated by the land-based wind energy experience. These trade-offs, especially when analyzed over time, are extremely complex and difficult to capture in the cost models we used in this study. As such, the cost results herein may not reflect the full realization of cost reductions due to industrialization and supply chain development and may understate some of the risk associated with upscaling.
- We estimate LCOE for a project envelope that extends to the point of interconnection. As such, we do not consider any costs that might be incurred by project owners from establishing the supporting port, manufacturing, and bulk transmission infrastructure. The overall extent and allocation of such expenditures are unclear, therefore we decided not to represent those in project LCOE.
- Our representation of the export system cable uses a straight-line distance from the offshore wind site to the nearest cable landfall to connect to an interconnection. This approach may underestimate export system cable costs because it does not consider cable routing, which often results in longer cable distance because of physical obstructions (e.g., peninsulas) or competing uses in the ocean.
- Costs have changed considerably over the past 3 years; we present costs that represent a 5-year average to better match the long-term horizon through 2050 of this study.
- The learning curve cost projections in this analysis rely on projections of expected global offshore wind energy deployment. The rate of global deployment growth determines how rapidly cost reductions occur over time. Rapid deployment accelerates cost reductions realized through industry learning and delayed deployment hinders how quickly cost reductions are realized. While this analysis relies on global deployment, there is also learning and supply chain maturation happening at the local/regional level not explicitly

modeled in this study. Investments in enabling infrastructure (such as ports, vessels, and transmission) are crucial for enabling cost-effective deployment in new markets.

- Modeling, including the modeling work done in this study, necessitates the use of assumptions to simplify reality into digestible information. Higher-fidelity modeling can help narrow the differences that will always exist between modeling output and reality. Some assumptions we have made in this study, such as inferring operational costs based on only select locations, can be improved on using higher-fidelity modeling. Similarly, we did not consider the impacts of siting constraints, which have the potential to restrict development in affected areas.

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Appendix A. Capital Cost Parameterizations

Monopile Cost Curve

The resulting monopile costs for an offshore wind energy project parametrized for 12 to 20 megawatts (MW) show a range of approximately $250–$350/kilowatt (kW) for a 40-meter (m) water depth (Figure A-1). Figure A-1 reports finished costs for the monopile (including materials and labor). Costs increase roughly linearly with water depth for a given wind turbine rating. The scatter in data points for each water depth indicates that the cost of the monopile (in $/kW) varies for wind turbines of different sizes. Larger wind turbines produce higher thrust loads, which require heavier (and more expensive) monopiles to resist the overturning moment from the thrust; however, because there would also be fewer large wind turbines required to produce a 600-MW project capacity, the cost of a project's monopiles decreases on a $/kW basis as turbine rating increases (Figure A-1). Transition piece costs are typically around 50%–75% of the monopile cost, depending on the water depth and wind turbine rating.

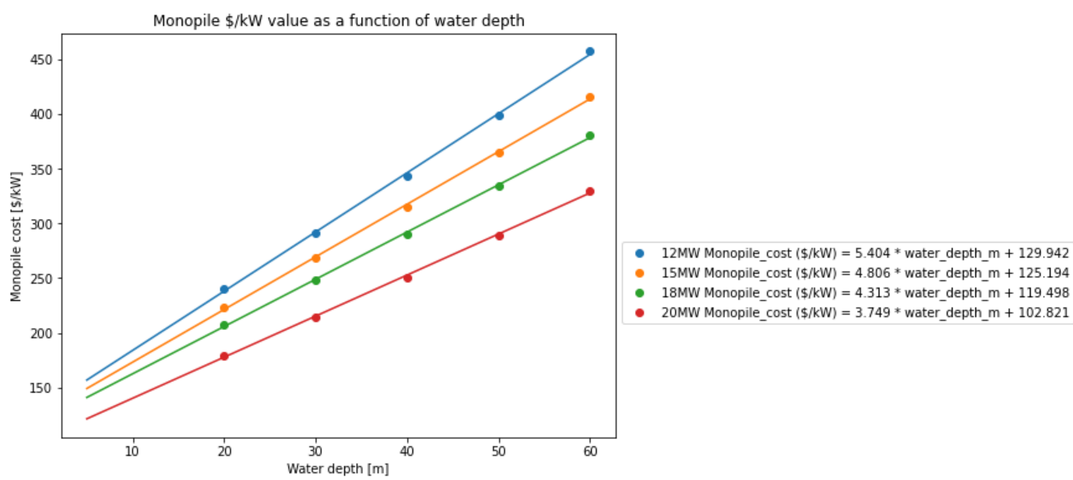

Figure A-1. Monopile costs and their variation by water depth developed using the Offshore Renewables Balance-of-system and Installation Tool.

Note: The figure shows expenditures for the monopile but excludes expenditures related to transportation and installation.

We compared these resulting cost estimates against higher-fidelity engineering designs obtained from the National Renewable Energy Laboratory's Wind-Plant Integrated System Design and Engineering (WISDEM®) model (WISDEM 2023). The Offshore Renewables Balance-of-system and Installation Tool (ORBIT) results are typically within +/- 30% of the costs estimated by WISDEM, with higher accuracy for 15-MW turbines below a 50-m depth (+/- 15%) and 20-MW turbines above a 40-m depth (+/- 15%). WISDEM does not estimate the cost of the transition piece.

Compared to the cost equations used in Beiter et al. (2016), the revised monopile costs are typically 15%–30% lower (on a $/kW basis) and the transition piece costs are typically +/-10%. This bias suggests that the extrapolation for monopile costs as wind turbine ratings grow beyond 10 MW (as used in earlier studies) likely overestimated mass. The newer methodology can be more easily adapted to new designs or water depths; however, we caution the reader that extrapolating these cost curves beyond the design envelope has not been validated against other tools or empirical data. Furthermore, this simple design study does not account for fatigue loading or adverse soil conditions that could require larger or heavier monopiles and correspondingly higher costs.

Semisubmersible Cost Curve

The design module represents the reference steel semisubmersible platform developed by Allen et al. (2020) to support the International Energy Agency's 15-MW reference wind turbine. The platform has four buoyant cylindrical columns (three radial, one central) connected by buoyant pontoons and radial struts. Allen et al. (2020) provide key geometric properties of the platform in their report. The geometry is simple enough that it can be readily defined in an ORBIT module. To provide high-level cost and mass scaling estimates for different wind turbine ratings, we implement the approach detailed by Roach et al. (2023). The authors developed detailed designs using a calibrated hydrodynamic model and then estimated scaling factors that link these designs together without the need for detailed engineering modeling. The scaling factors (α) can be applied to different geometric parameters of the model as a function of the ratio of rotor radius between the baseline (15 MW) and target wind turbine ratings as shown in the following equation:

$$\frac{\text{Parameter}_1}{\text{Parameter}_2} = \left(\frac{\text{Radius}_1}{\text{Radius}_2}\right)^{\propto} \qquad \text{(A-1)}$$

We implement this upsizing approach in ORBIT's semisubmersible design module to resize the column and pontoon geometry (such as the diameter, height, and radial location of the buoyant columns) while holding wall thickness constant. By running a parametric sweep over various wind turbine ratings, we derive a cost curve that reflects the subsequent changes in platform design (Figure A-2).

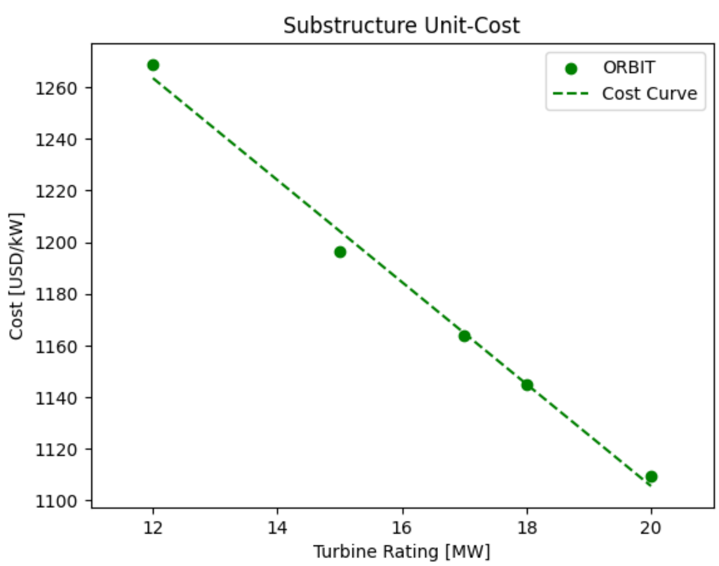

Figure A-2. Semisubmersible costs and their variation by turbine rating

We find that the normalized unit cost of the semisubmersible (in $/kW) decreases as wind turbine rating grows from 12 to 20 MW, indicating that the mass of structural steel needed for the platform increases at a lower rate than the turbine rating. The absolute cost of the platform (in $) would still increase approximately linearly with turbine rating. This result is challenging to validate because of the absence of commercialized floating platforms. We have verified the overall cost of the 15-MW platform (around $1,200/kW) with floating platform technology providers, which assumes that a relatively mature supply chain exists and a commercial-scale project can benefit from economies of scale from bulk orders. The $/kW costs at the edge of the domain (12 MW and 20 MW) are within 10% of this verified cost. These costs do not include the transport and installation of the semisubmersible, which we capture under the separate cost line item "Installation and Assembly."

Export Cable Cost Curve

We used ORBIT to reassess the export system cable costs, estimating the costs for both a high-voltage alternating current (HVAC, using 220-kilovolt [kV] export cables) and high-voltage direct current (HVDC, using 320-kilovolt cables) system for cable distances of 10-400 kilometers (km). For the dynamic array cables that are required for floating offshore wind applications, we assumed 20% higher costs than the static array cables used for fixed-bottom offshore wind. Although HVDC cables are still not produced at a commercial scale (and therefore have uncertain costs), this cost increase has been informed by consulting with leading floating offshore wind energy developers. We found a crossover point at an approximately 70-km cable length at which HVDC cables become less costly than HVAC cables. We then connect the HVAC cost curve for distances below the crossover point to the HVDC curve for distances greater than the crossover point to produce a single cost curve for export system costs. Our resulting cost relationship (inclusive of installation costs, offshore substation, and onshore DC converter if appropriate) shows this crossover point as part of a parametrized curve fit (Figure A-3).

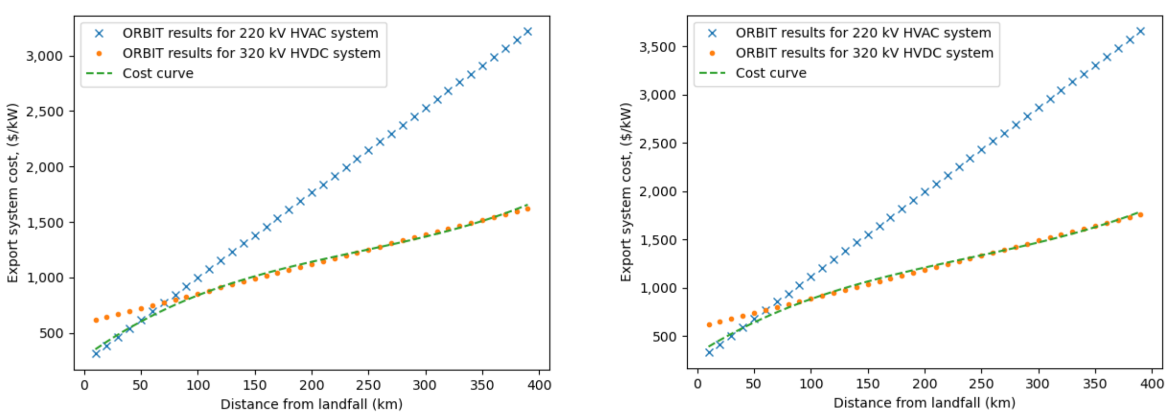

Figure A-3. Export system cable costs and their variation by distance from landfall for fixed-bottom (left) and floating (right) offshore wind energy

The newly derived cost curves show that the export system could cost between $500 and $1,300/kW for projects located 20–200 km from their point of interconnection. The substations represent significant fixed costs that do not vary with distance to shore, and the variance as a function of distance is due to the increased cable length. This cost curve is generated assuming a

1-gigawatt project; increased project capacities could require additional cables and/or substations, which could cause project costs to depart from this cost curve. Ultimately, the design of the export system is a significant cost contributor to the capital stack of an offshore wind project and will be customized for each individual project.

The assumptions and results from the new ORBIT design module have been reviewed by industry experts to verify the new methodology. The updated cost estimates show a significant increase relative to 2016 costs.

Appendix B. Operations and Maintenance Parameterizations

We assessed operations and maintenance (O&M) costs for eight geographic regions representing future offshore wind energy deployment in the United States, using wind and wave time series from ERA-5 (Hersbach et al. 2020). The operational expenditures (OpEx) were modeled for a 1-gigawatt wind power plant using 15-megawatt wind turbines, and the output values were then scaled for different turbine sizes as needed for this study. Significant wave height distributions for the selected sites show there is much spatial variation in wave conditions on a regional scale (Figure B-1). Vessel access to offshore wind sites was modeled to occur only when wave heights are below operational limits, which are 2 to 4 meters (m) depending on the type of vessel. We modeled floating wind plant O&M costs in all eight regions, and fixed-bottom wind plant O&M costs in the Atlantic and Gulf of Mexico. At each location, we simulated O&M costs for port distances between 20 and 400 kilometers (km). Up to 80 km, crew transfer vessels travel from the port to the wind plant site for regular maintenance activities. Beyond 80 km, a service operations vessel is stationed at sea for 2-week periods (with 1-week intervals back at port) to conduct minor repairs and routine maintenance.

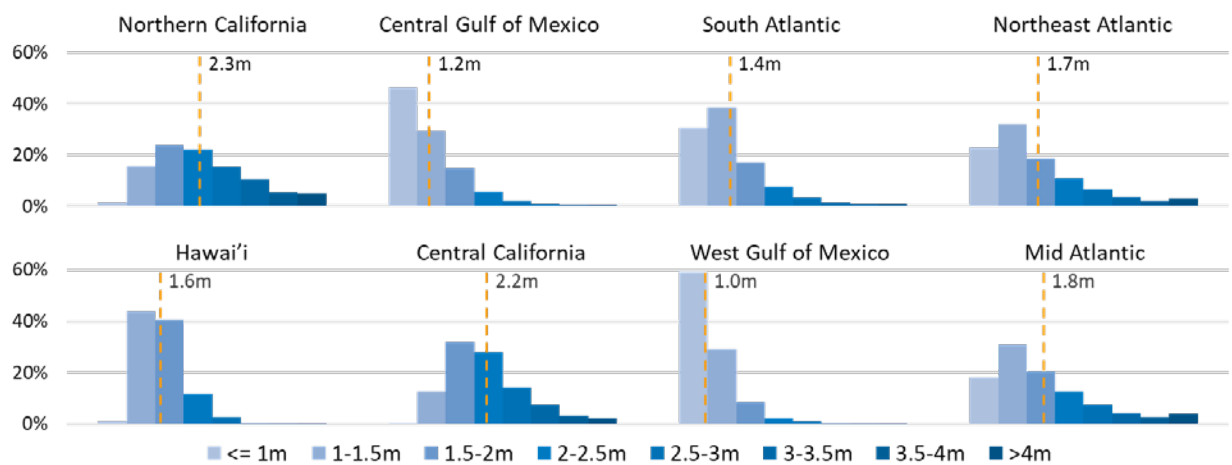

Figure B-1. Significant wave height frequency distributions for selected sites from 2017 to 2022. Vertical dashed lines indicate average significant wave height at each location.

The OpEx values resulting from these different scenarios can be presented in the form of a cost curve for both fixed-bottom and floating substructures (Figure B-2). In both cases, the OpEx value increases with greater distance to port and increasing wave height. Note that the total OpEx costs for fixed-bottom substructures are in general higher than the costs required for floating.

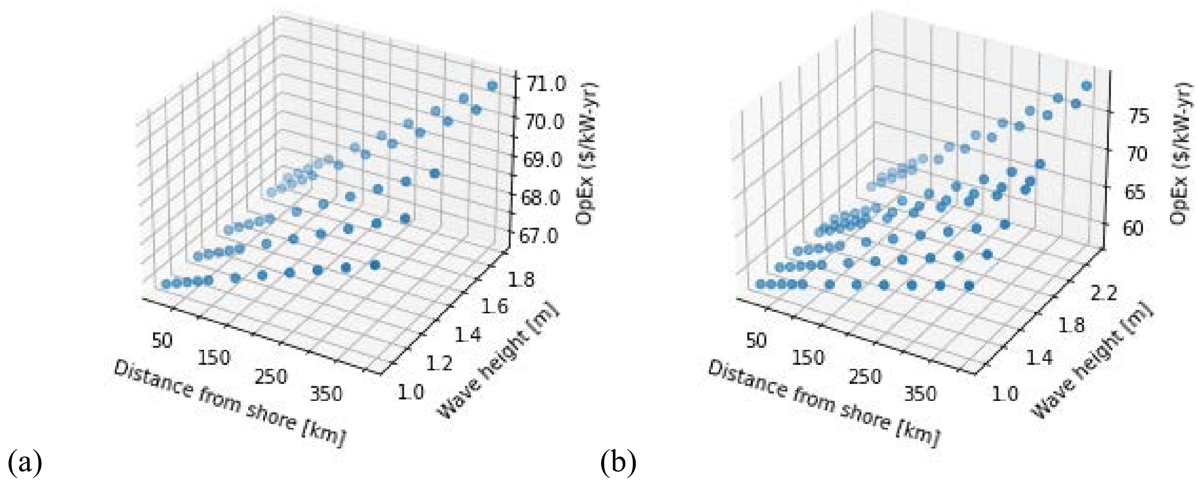

Figure B-2. OpEx modeled values for a 15-megawatt turbine for (a) fixed-bottom and (b) floating substructures

This cost curve (Figure B-2) is useful because we can approximate the magnitude of the OpEx values for a variety of scenarios with a range of wave heights and distance to operations port. To exercise this functionality, this curve was incorporated into our model framework (Section 6.7) to approximate OpEx values in locations that were not run specifically at a higher fidelity by the Windfarm Operations and Maintenance cost-Benefit Analysis Tool (WOMBAT) model.