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National Renewable Energy Laboratory

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A20-87161
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Suggested Citation
Eberle, Annika, Trieu Mai, Owen Roberts, Travis Williams, Pavlo Pinchuk, Anthony Lopez, Matthew Mowers, Joseph Mowers, Tyler Stehly, and Eric Lantz. 2024. *Incorporating Wind Turbine Choice in High-Resolution Geospatial Supply Curve and Capacity Expansion Models*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87161. https://www.nrel.gov/docs/fy24osti/87161.pdf.

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Golden, CO 80401
303-275-3000 • www.nrel.gov

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This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office (DOE EERE WETO). The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

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Acknowledgments

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We would like to thank the following individuals for their helpful reviews and support:

- Paul Veers, Brian Smith, Emily Newes (National Renewable Energy Laboratory)
- Ahti Simo Laido and Lena Kitzing (Technical University of Denmark)
- Sandra Sattler (Union of Concerned Scientists)
- Gage Reber and Patrick Gilman (DOE EERE WETO).

We are also grateful to Billy Roberts for visualization and cartography support, Emily Horvath and Sheri Anstedt for editing support, and DOE EERE WETO for their support.

List of Acronyms

AEP	annual energy production
ATB	Annual Technology Baseline
BOS	balance of systems
CO_2	carbon dioxide
CONUS	conterminous United States
CSM	Cost and Scaling Model
D	rotor diameter
FOA	funding opportunity announcement
GW	gigawatt
HH	hub height
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
km	kilometer
KTS	Keystone Tower Systems
kW	kilowatt
LandBOSSE	Land-based Balance-of-System Systems Engineering model
LCOE	levelized cost of energy
LCOT	levelized cost of transmission
m	meter
m/s	meters per second
MW	megawatt
MWh	megawatt hour
NREL	National Renewable Energy Laboratory
OEM	original equipment manufacturer
OpEx	operational expenditures
ReEDS	Regional Energy Deployment System
reV	Renewable Energy Potential
TR	turbine rating
TWh	terawatt hour

Executive Summary

Wind energy is a growing source of electricity generation in the United States and provided more than 10% of total U.S. utility-scale electricity generation in 2022 (U.S. Energy Information Administration 2023). To achieve national decarbonization goals, U.S. annual deployment of wind energy will need to increase by at least fivefold compared to the recent past (United States Department of State and the United States Executive Office of the President 2021; Denholm et al. 2022; Jenkins et al. 2021). Modeling and analysis tools can be used to inform how to enable these increased levels of wind energy deployment. For example, prior research has quantified the costs, benefits, and other impacts of wind energy technologies and assessed how wind energy might contribute to decarbonization goals. However, most of these prior studies relied on generalized representations of wind energy technologies (e.g., a single wind turbine or an average capacity density). These generalized approaches did not allow the studies to evaluate how multiple wind energy technologies might perform under a range of siting conditions.

Technology advancements (e.g., segmented blades, crawling cranes, on-site manufacturing) are expected to enable turbine upsizing, including taller towers, and increase the competitiveness of wind energy. However, larger turbines and towers can be more challenging to transport and site (e.g., siting ordinances based on height limits or setbacks from buildings, property lines, roads, and other infrastructure may limit which technologies can be deployed at a given location). Other technology innovations (e.g., modified operation and maintenance strategies) could also increase the competitiveness of different turbine technologies at specific locations. Thus, it is important to incorporate more detailed representations of turbine technology and their interactions with siting considerations to assess the deployment potential of these technologies.

We hypothesize that incorporating location-specific wind plant layout design and customized turbine choice into our modeling tools could allow for more optimized deployment of technologies by location and result in increased deployment of wind energy technologies. To explore this hypothesis, we present a new method that incorporates wind turbine choice into the technology representation of land-based wind energy in long-term planning models. Our method integrates three previously published modeling and analysis capabilities: 1) bottom-up cost modeling to estimate future technology costs, 2) geospatial modeling to represent siting decisions, and 3) power sector modeling to evaluate potential deployment. We refer to this approach as a "customized turbine choice" methodology because it creates a composite turbine scenario by choosing from multiple wind turbine technologies—using site-specific optimized turbine layout and selecting the least-cost technology at each location. As described in Section 2.1, we model four different near-future wind energy technologies: 1) a standard 6.0-megawatt (MW) turbine, which is anticipated to be the typical turbine deployed in 2030, 2) a site-constrained 8.3-MW turbine that is relevant to locations with more land constraints, 3) a low-wind 3.3-MW turbine, which has a low specific power that presents advantages in areas with lower wind resource, and 4) a tall tower 6.0-MW turbine, which uses a larger rotor diameter and taller tower. We model these turbines individually and use our customized turbine choice methodology to develop a least-cost composite supply curve that comprises all four technologies.

When we compare the individual supply curves of each of the four technologies to the composite supply curve, we find that although the differences in annual energy production and capacity vary by location and technology, the composite supply curve could enable up to 29% more capacity and 27% more energy than a supply curve developed with a single wind turbine. To explore how benefits of using a composite supply curve change our estimates of wind energy deployment, we implement these supply curves in our power sector model. As described in Section 2.3, because our power sector modeling results differ depending on future conditions, we examine five scenarios of the U.S. electricity system: Reference, Limited, Advanced, Conservative, and Low Carbon. In all scenarios, the composite supply curve resulted in more generation from land-based wind in 2040 compared to when a single individual turbine was modeled. However, in some cases (e.g., before 2030 and in our Low Carbon scenario), the land-based wind capacity of the composite supply curve was lower, and the power system cost and electric sector carbon dioxide emissions increased.

The intent of this report is to describe one possible approach for increasing the fidelity of turbine choice in power sector modeling, evaluate how this approach changes the results of our capacity expansion models, and clarify whether further research is warranted. Our findings indicate that customizing wind turbine choice in capacity expansion models could lead to higher estimates of future wind energy deployment and better capture the role wind energy could play in supporting decarbonization efforts. Future research is needed to further explore the implications of our proposed methodology and better inform decision making around wind turbine choice.

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1 Introduction

Wind energy is a low-cost source of renewable energy that can be used to enable decarbonization goals (U.S. Department of Energy Wind and Water Power Technologies Office 2015). For the United States to achieve an economywide target of net-zero emissions of greenhouse gases by 2050, annual deployment of wind energy in the United States will need to increase by at least fivefold compared to historical deployment rates (United States Department of State and the United States Executive Office of the President 2021; Denholm et al. 2022; Jenkins et al. 2021). Modeling and analysis frameworks (e.g., techno-economic analysis, expert elicitation, power sector modeling, and studies of technical potential) can help inform where and how wind energy deployment might occur under different future conditions and thereby help enable the achievement of decarbonization goals.

Prior wind-related modeling and analysis research has evaluated potential pathways for enabling increased wind energy deployment, including quantifying the costs, benefits, and other impacts of wind energy technologies. For example, the Wind Vision Report (U.S. Department of Energy Wind and Water Power Technologies Office 2015) explores pathways, actions, and achievements that would enable wind energy deployment to contribute to future U.S. electricity needs, including decreasing the environmental impact of electricity generation technologies. The National Renewable Energy Laboratory's (NREL's) Standard Scenarios (produced annually; latest publication: Gagnon et al. [2022]) use a standardize set of energy technology cost and performance data from the Annual Technology Baseline (ATB) NREL 2023) to perform power sector modeling and explore deployment, production, costs, and emissions for a range of possible futures of the U.S. electricity sector. Jenkins et al. (2021) also evaluate the physical infrastructure, capital mobilization, land use, energy workforce, and air pollution and public health implications of five potential net-zero energy transition pathways.

Several existing techno-economic modeling tools also assess the costs of current and future wind energy technologies. Land-based wind and offshore wind market reports describe trends in installation, industry, technology, performance, and cost (R. Wiser et al. 2023; Musial et al. 2022). Other engineering assessment and expert elicitation studies explore how technology innovations might enable cost reductions and performance improvements and thereby increase deployment of wind energy technologies (Dykes et al. 2017; Nicholas Johnson et al. 2019; Nick Johnson et al. 2021; Verdolini et al. 2018; R. Wiser et al. 2021; Bolinger et al. 2021). Researchers have also evaluated the theoretical, geographic, technical, economic, and feasible potential of wind energy to better understand how and where wind energy technologies might be deployed (Maclaurin et al. 2020; Lopez et al. 2021; McKenna et al. 2022; Mai et al. 2021; Roberts et al. 2023).

Most of these prior studies have examined a limited set of wind energy technologies (e.g., a single turbine) over a range of siting conditions and power sector modeling scenarios. However, empirically there are regional differences in turbine choice. For example, wind turbines installed near the Great Lakes recently tend to have taller towers than the same turbines installed elsewhere. The U.S. Interior region also tends to have turbines with a higher specific power than other locations due to the high-quality wind resource in the region. In addition, technology advancements, particularly upsizing trends (i.e., larger rotors, taller towers, and higher turbine ratings), are expected to further increase the competitiveness of wind energy in traditional development-rich regions and increase access to new markets (Wiser et al. 2021). For example, taller towers may enable economic wind energy development in the southeastern United States, which has relatively poor wind resources at ~100 meters (m) above ground but greater average wind speeds at higher hub heights (Lantz et al. 2019). Although the technical advantages of upsizing are well-documented, increasing turbine and tower size can introduce additional challenges. The logistics of turbine installations, such as blade transport and cranes for tower erection, can be more challenging with larger machines (Lantz et al. 2019). And, an increasing number of siting ordinances based on height limits or setbacks (from buildings, property lines, roads, and other infrastructure) might also limit the technology options available in some locations (Lopez et al. 2023). Given these regional factors, assessments of wind technical potential and deployment scenarios would benefit from considering a broad range of wind technologies and their interactions with realistic siting considerations. However, identifying which turbine is most suitable for each location can be challenging given the myriad of factors (such as the wind resource, future turbine costs, and siting considerations) involved in the selection process.

We present one approach for considering multiple turbine technologies within long-term planning models. This new modeling methodology increases the granularity of land-based wind energy technology representation by identifying a composite wind energy supply curve that combines multiple turbines into a single national supply curve by associating one of four[1] individual turbine options with each location based on the lowest levelized cost of energy (LCOE). The method includes three components: 1) performing bottom-up, component-level cost modeling to estimate future technology costs for multiple wind turbine and plant configurations, 2) performing geospatial modeling to represent siting decisions, including least-cost optimization for plant layout down to the individual turbine resolution under multiple siting constraints, and 3) performing power sector modeling that can evaluate multiple turbine technologies based on a composite supply curve. By modeling multiple wind turbine options and incorporating land use factors specific to each wind site[2], this method can find a tailored lowest cost technology solution for each site and thereby increase the location-specific representation of turbine selection within long-term capacity expansion modeling. Because our approach uses site-specific optimized turbine layout and customized turbine selection (where each plant is fitted with a single turbine configuration selected from four pre-defined wind turbine technology options), we refer to it as a “customized turbine choice” modeling methodology.

We demonstrate the capabilities of this new modeling pipeline by examining how turbine selection might evolve from 2021 through 2040. We use this case study to explore how much turbine choice might influence our estimates of U.S. wind energy deployment. We hypothesize that location-specific customized wind plant layout design and turbine choice could enable lower

[1] As described in Section 2.1, we model four different near-future wind energy technologies: 1) a standard 6.0-megawatt (MW) turbine, which is anticipated to be the typical turbine deployed in 2030, 2) a site-constrained 8.3-MW turbine that is relevant to locations with more land constraints, 3) a low-wind 3.3-MW turbine, which has a low specific power that presents advantages in areas with lower wind resource, and 4) a tall tower 6.0-MW turbine, which uses a larger rotor diameter and taller tower.

[2] A “wind site” is defined using the reV model (Maclaurin et al. 2020; Lopez et al. 2021), which subdivides the conterminous United States into a grid of 11.5-kilometer (km)-by-11.5-km sites and, for each site, estimates the deployable potential (MW), available hourly and annual generation (megawatt-hour [MWh]), capital costs ($/kilowatt [kW]), grid connection costs ($/kW), LCOE ($/MWh), levelized cost of transmission (LCOT; $/MWh), and total LCOE (LCOE + LCOT; $/MWh).

costs and better integration of wind power into communities, supporting lower electric sector emissions, enhancing societal benefits, and mitigating renewable energy siting challenges. Our intent is to evaluate how much turbine choice changes the results of our capacity expansion models and clarify whether further research is warranted. Our results show that using our customized turbine choice methodology could lead to higher estimates for wind future deployment. Our findings also suggest an expansion of opportunities for competitive wind deployment in the United States and indicate that more simplified modeling might underestimate the role that wind energy could play in meeting decarbonization goals. Future research is needed to further explore the implications of turbine choice and to better inform technology researchers, original equipment manufacturers, and other wind industry stakeholders about the market potential of different wind turbine technologies.

2 Methodology

Our customized turbine choice methodology involves connecting three previously published modeling and analysis capabilities via multiple steps, as demonstrated in Figure 1. The core capabilities include 1) projecting wind technology performance and costs using bottom-up scaling approaches for multiple distinct turbines, 2) performing geospatial modeling to select appropriate turbine technologies and layouts for each location and create a composite wind energy supply curve, and 3) performing power sector modeling to estimate future wind energy deployment based on the composite supply curve and wind cost projections.

The methodology outlined here relies on approaches used in other prior studies performed by the NREL (Gagnon et al. 2022; T. Mai et al. 2021; T. T. Mai et al. 2017). However, there are three key distinctions that enable this new customized turbine choice methodology to reflect wind energy technology advancements more directly and robustly. The first is its consideration of multiple turbines with distinct configurations in terms of capacity ratings, tower heights, and rotor diameters. Second, future costs of each turbine and associated wind power plant are also projected using component-level scaling in 2030. Third, the geospatial modeling to develop the resource potential accounts for the different turbine configurations by dynamically creating tailored layouts based on wind resource, costs, performance, and land use requirements for each site. These different turbines, their resource potential, and cost and performance characteristics are all modeled for the power sector modeling scenarios. In contrast, previous methods were based on a generalized representation of a single turbine technology using constant assumptions for capacity density, losses, and specific power, which did not allow for detailed representation of any given turbine technology or robust representation of multiple turbine technologies (Gagnon et al. 2022).

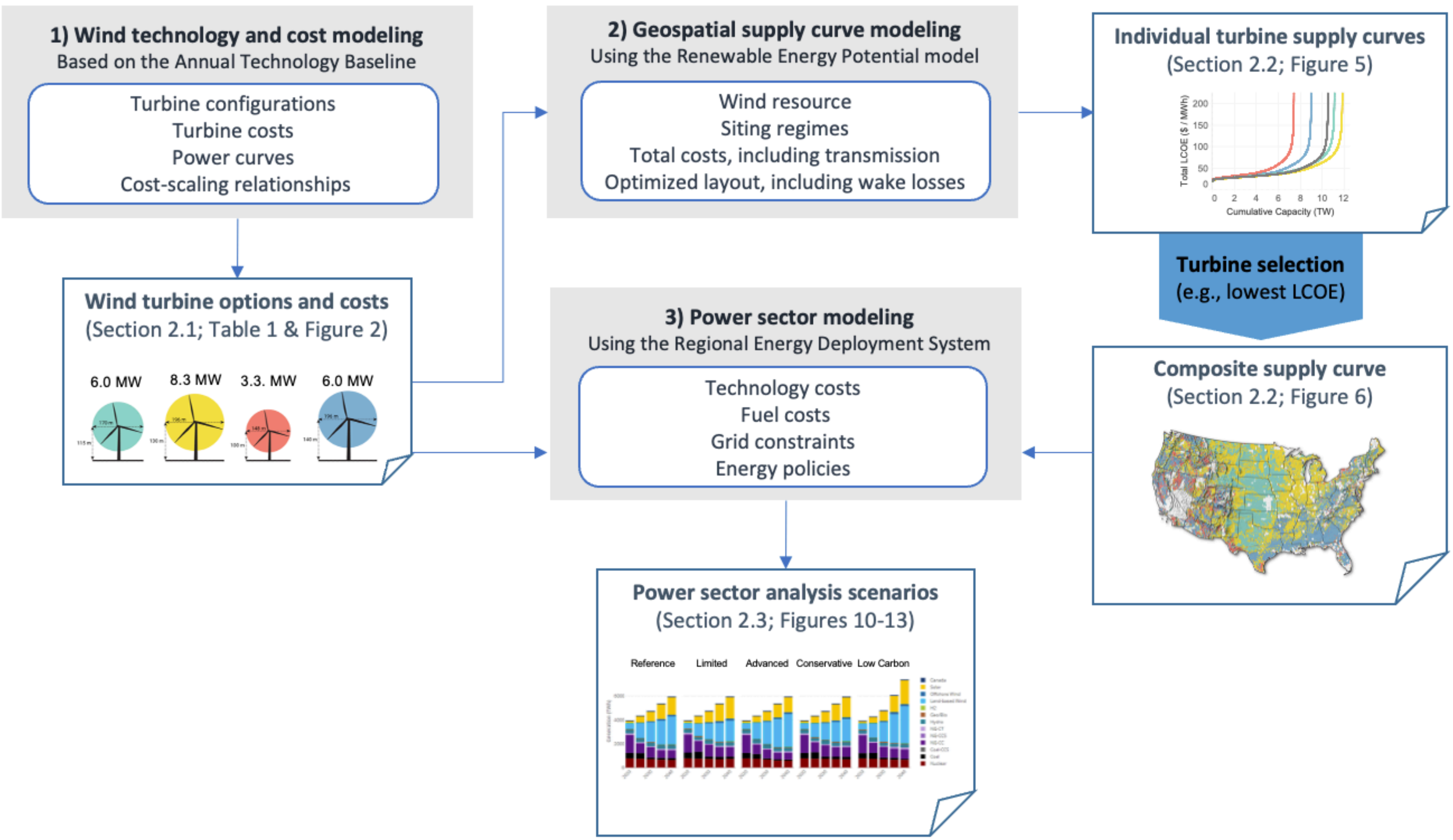

Figure 1. Customized turbine choice methodology flow chart.

Our customized turbine choice methodology integrates three previously published modeling and analysis capabilities: 1) the Annual Technology Baseline (National Renewable Energy Laboratory 2023), which uses the Cost and Scaling Model (Fingersh, Hand, and Laxson 2006) and the Land-based Balance-of-System Systems Engineering model (Eberle et al. 2019); the Renewable Energy Potential model (Maclaurin et al. 2020; Lopez et al. 2021; Stanley et al. 2022); and the Regional Energy Deployment System model (Ho et al. 2021; Mai et al. 2021; Gagnon et al. 2023).

2.1 Wind Technology and Cost Modeling

The first step in the customized turbine choice methodology is to select a set of distinct wind turbine configurations and estimate their costs and performance.

2.1.1 Wind Turbine Configurations

Table 1 outlines specific characteristics for each of the four wind turbine configurations, including estimated overnight capital costs and operating expenditures in 2030 for three cost scenarios: Conservative, Moderate, and Advanced (see Table 2 for assumptions used in each cost scenario). These turbine technology characterizations were developed for the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023) and span a range of characteristics, including power rating, hub height, rotor diameters, and specific power. They were selected to assess how different designs might interact with wind plant economics and siting considerations.

Table 1. Wind Turbine Configurations and Estimated Costs in 2030[a]

		Standard 6.0 MW	Site Constrained 8.3 MW	Low Wind 3.3 MW	Tall Tower 6.0 MW
Turbine rating (MW)		6.0	8.3	3.3	6.0
Rotor diameter (m)		170	196	148	196
Specific power (W/m^2)		264	275	192	199
Hub height (m)		115	130	100	140
Overnight capital cost in 2030 ($/kilowatt [kW] for 200-MW plant)	*Con.*	1,200	1,296	1,276	1,686
	Mod.	1,083	1,134	1,190	1,447
	Adv.	1,032	1,067	1,160	1,344
Operating expenditures in 2030 ($/kW-year)	*Con.*	28.7	26.9	30.0	23.7
	Mod.	27.0	24.6	35.1	27.0
	Adv.	23.7	22.3	36.3	28.7

Abbreviations: *Con.* = Conservative scenario; *Mod.* = Moderate scenario; *Adv.* = Advanced scenario.

a) Turbine technology characterizations and costs are based on the 2023 Annual Technology Baseline R&D Only financial case, which holds tax and inflation rates constant at assumed long-term values (21% federal tax rate and 2.5% inflation rate) and excludes the effects of tax credits (NREL 2023). These turbine configurations and estimated costs assume that a series of innovations (i.e., on-site manufacturing, spiral-welded towers, alternative erection technologies, segmented blades, and controls advancements) can reduce transportation challenges and improve the performance of next-generation wind turbines by 2030 (see the appendix for details). These assumptions are intended to reflect future conditions as the industry continues to evolve and innovate. Alternative assumptions (e.g., alternative timelines for technology evolution, fewer or modified innovations, or different logistical constraints) would change the costs for each technology.

Although this set of turbines is not comprehensive, it represents a range of plausible designs that were developed in consultation with industry and the U.S. Department of Energy Office of

Energy Efficiency and Renewable Energy Wind Energy Technologies Office (DOE EERE WETO) to approximate the range of technology expected to be available in 2030 (Wood Mackenzie 2021; International Renewable Energy Agency (IRENA) 2019; NREL 2023). While not all these configurations are currently available, turbines that are nearly of this scale are commercially available now and are expected to be installed at select sites in the United States in the 2020s (NREL 2023). The characteristics of these representative turbines are compared with a 2021 market average turbine in the appendix.

2.1.2 Wind Turbine Costs, Power Curves, and Cost-Scaling Relationships

There is a high degree of uncertainty in developing future cost projections. To capture a range of future costs, we estimate wind turbine technology costs for three cost scenarios—Conservative, Moderate, and Advanced (Table 2). Figure 2 provides an overview of the costs and performance characteristics for each of the four technology configurations[3] considered in this analysis. Refer to the appendix for more details about the cost modeling assumptions.

[3] The wind turbine names in the report were chosen to enable quick comparisons across technologies. The Standard 6.0 MW is expected to be the standard turbine deployed in 2030. The specifications for the Site-Constrained 8.3-MW were developed to consider sites with more land constraints. The Low-Wind 3.3 MW is a low-specific-power machine that presents advantages in areas with lower wind resource. The Tall Tower 6.0 MW has the same turbine rating as the standard 6.0 MW, but it uses a larger rotor diameter and taller tower.

Table 2. Summary of Assumptions Used in Cost Scenarios[a]

Cost Scenario	Year		
	2021	*2030*	*2050*
Conservative	Capital costs are estimated using **bottom-up turbine component scaling relationships and process-based balance-of-systems modeling** of current technology.	Capital costs are calculated based on conservative **historical capital cost learning rates that vary by technology** with an 8% base learning rate.	Capital costs are back **calculated from the levelized cost of energy (LCOE)** using a conservative historical LCOE learning rate of 10%.
Moderate	Capital costs are estimated using **bottom-up turbine component scaling relationships and process-based balance-of-systems modeling** of current technology.	Capital costs are estimated using **bottom-up turbine component scaling relationships and process-based balance-of-systems modeling**, incorporating near-term turbine technology and balance-of-system innovations.	Capital costs are back **calculated from the LCOE** using a moderate historical LCOE learning rate of 14%.
Advanced	Capital costs are estimated using **bottom-up turbine component scaling relationships and process-based balance-of-systems modeling** of current technology.	Capital costs are calculated based on aggressive **historical capital cost learning rates that vary by technology** based on the moderate scenario's bottom-up engineering-based cost modeling of each technology in 2030 (25% base learning rate).	Capital costs are back **calculated from the LCOE** using an aggressive historical LCOE learning rate of 20%.

a) Cost scenario assumptions are based on the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023). There is a high degree of uncertainty in developing future cost projections. To represent a range of potential future costs, these scenarios integrate two cost modeling approaches: 1) bottom-up turbine component scaling relationships and process-based balance-of-systems modeling and 2) learning rates.

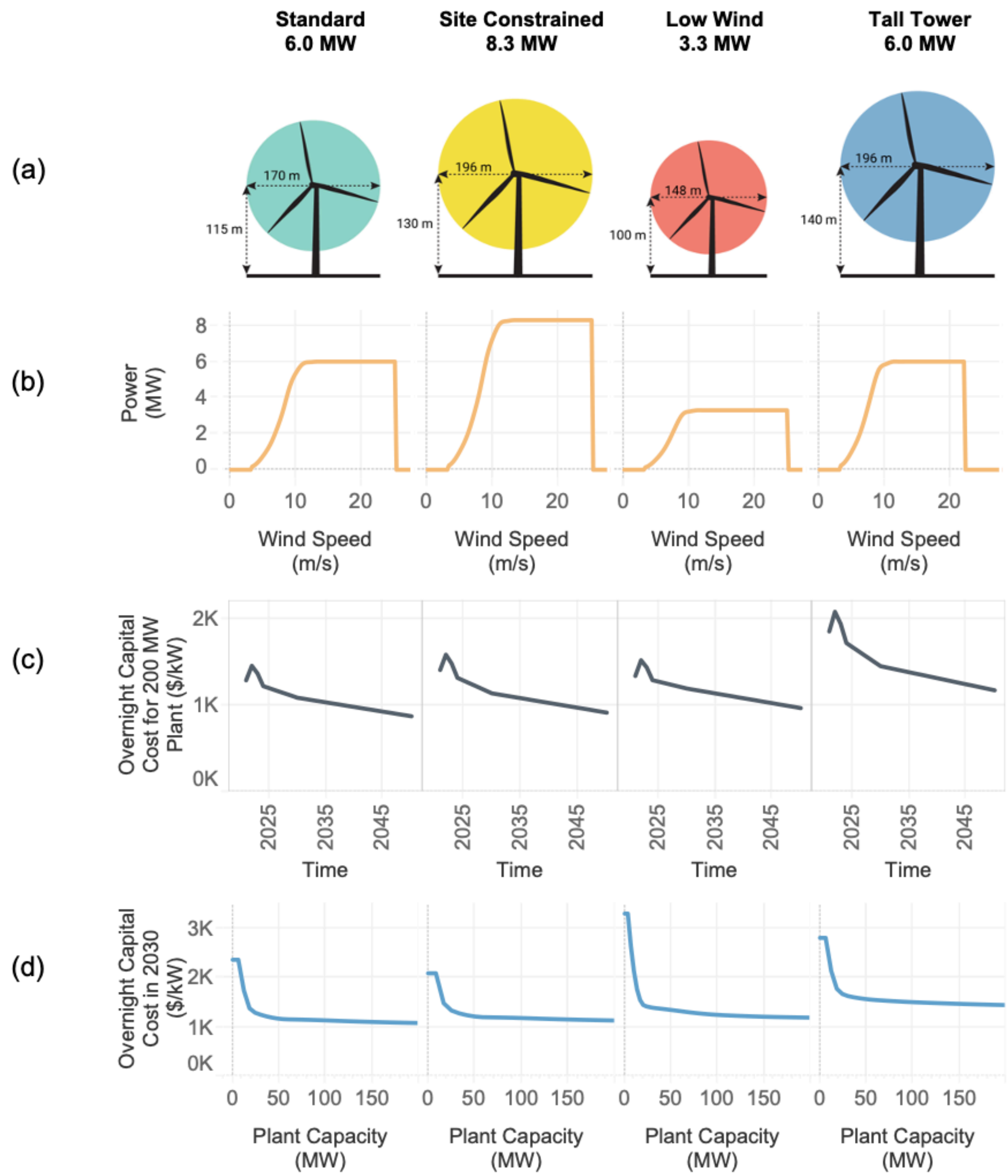

Figure 2. Overview of wind turbine configurations, power curves, and capital costs.

The first row (a) depicts the turbine configuration, including the rotor diameter and hub height (see Table 1 for more details about each configuration). The second row (b) illustrates the power curve for each turbine. The third row (c) shows how the overnight capital costs[4] change over time for each turbine technology for a given plant size (in this case, 200 MW) in the Moderate scenario. The last row (d) outlines how the capital costs for the Moderate scenario in 2030 change with plant size and capture the economies of scale that could be realized at larger plant sizes.

As outlined in Table 2 (and further described in the 2023 ATB NREL 2023]), we use a combination of historical learning rates and bottom-up cost and scaling relationships to estimate the capital costs for the turbine and balance of systems (BOS). To incorporate variations over

[4] Overnight capital costs are the capital expenditures that would be required if the plant could be constructed overnight (i.e., excludes construction period financing).

time (Figure 2c), each scenario involves estimating capital costs at three distinct points in time: 2021, 2030, and 2050. Between 2021 and 2030 and between 2030 and 2050, capital costs are linearly interpolated.[5]

To calculate the capital costs for all three scenarios in the base year (2021) and the Moderate scenario in 2030[6], we use bottom-up turbine component scaling relationships and process-based BOS modeling to estimate how much it would cost to install each type of turbine within a hypothetical wind plant. Our bottom-up cost modeling approach allows us to capture changes in capital cost and BOS economies of scale that result from increasing turbine rating, hub height, and plant size. For example, the Tall Tower 6.0 MW has a higher hub height and larger rotor, which results in the largest capital cost across all four turbines. However, although the Site Constrained 8.3 MW has a similar rotor diameter and hub height, its capital cost is lower because the higher turbine rating requires fewer turbines to reach the same plant size (refer to Key, Roberts, and Eberle (2021) for a more detailed explanation of cost scaling relationships).

When using the bottom-up approach, we derive turbine component and transportation cost estimates using NREL's Cost and Scaling Model (CSM) (Fingersh, Hand, and Laxson 2006; NREL 2019) with component masses and costs calculated based on relationships of hub height, rotor diameter, and turbine rating.[7] To estimate BOS costs, we use NREL's Land-based Balance-of-System Systems Engineering (LandBOSSE) model (Eberle et al. 2019), which estimates wind plant installation costs for eight types of BOS activities: site development, management, site preparation, foundation construction, turbine erection, collection system construction, grid connection, and substation construction. Refer to the appendix for more details about the cost modeling methodology (e.g., Figure A-1 shows how much the turbine, BOS, and transportation components cost contribute to the total capital cost for each turbine technology; Figures A-2 and A-3 show how the turbine cost and BOS cost, respectively, break down into the underlying components).

To incorporate economies of scale in BOS costs, we execute LandBOSSE from a plant size of 0 MW to 1 gigawatt (GW) at multiple increments of each turbine rating (e.g., 0 to 303 turbines for Low Wind 3.3 MW). Figure 2d illustrates how the capital costs vary based on these economies

[5] In 2022 and 2023, average capital cost multipliers of 15% and 10%, respectively, are applied to the capital costs to account for supply chain stress, high commodity prices, and increased logistics costs (these inflationary impacts are assumed to recover around 2024) (Wood Mackenzie 2022; Vestas 2022; International Energy Agency 2021).

[6] For the Moderate scenario in 2030, our bottom-up modeling incorporates six near-term turbine technology and BOS innovations, including: segmented blades longer than 70 meters (m), which reduce transport costs and increase blade manufacturing and installation costs; advanced manufacturing, which reduces blade mass and enables larger rotors; spiral-welded towers (both factory and on-site manufactured), which decrease tower manufacturing costs; on-site manufacturing also removes transportation limits to tower size, enabling greater hub heights; improved turbine and tower designs that enable lighter weight nacelles and fewer tower sections, which decreases transportation costs; climbing cranes, which reduce the cost of erecting the turbine and enable greater hub heights; reduced turbine spacing because of wake steering, which reduces access road costs and collection costs. We revised the relationships in the CSM to reflect changes in component mass scaling relationships that might result from each of these innovations (refer to the appendix for details).

[7] Many of these interrelationships were adjusted to reflect 2020 empirical turbine component masses for land-based turbines between 2.5 MW and 6 MW offered by General Electric, Nordex, Siemens Gamesa Renewable Energy, and Vestas. Transport costs do not capture site-specific transport costs, but average site costs were based on current and near-future turbines as reported by the U.S. Department of Energy's Big Adaptive Rotor project (Nick Johnson et al. 2021).

of scale for each turbine in the Moderate scenario in 2030 (there are limited reductions in capital costs beyond 200 MW, so this figure illustrates variations only from 0 MW to 200 MW).

Other cost and performance assumptions, such as the operational expenditures (OpEx) and net capacity factor, rely on the technology configurations outlined in the 2023 ATB NREL 2023). For example, in the Moderate scenario, we use literature estimates for OpEx that consider economies of scale associated with turbine rating (lower OpEx as turbine rating increases). In addition, we derive the net capacity factor from the power curves (shown in Figure 2b) combined with system loss assumptions (e.g., in the Moderate scenario, total system losses are assumed to be 13.4% in 2030 and 12% in 2050). Refer to the 2023 ATB for more details.

2.2 Geospatial Supply Curve Modeling

The second step in the customized turbine choice methodology is to perform geospatial modeling to define the siting regimes (i.e., the siting assumptions used to determine infrastructure, regulatory, and physical siting exclusions), optimize turbine layout to select a turbine for each location, and create supply curves (i.e., four individual supply curves comprised of each technology by itself, and one composite wind energy supply curve comprised of multiple technologies with the least-cost technology chosen at each location after wind speed thresholds are applied).

2.2.1 Wind Resource, Siting Regimes, and Calculation of Total Costs

For this analysis, we use the geographic-information-system-based Renewable Energy Potential (reV) model (Maclaurin et al. 2020; Lopez et al. 2021) to examine the siting suitability of wind power plants. The reV model subdivides the conterminous United States (CONUS) into 11.5-kilometer (km)-by-11.5-km "wind sites" and, for each site, estimates deployable potential (MW), available hourly and annual generation (megawatt-hour [MWh]), capital costs ($/kilowatt [kW]), grid connection costs ($/kW), LCOE[8] ($/MWh), levelized cost of transmission (LCOT; $/MWh), and total LCOE (LCOE + LCOT; $/MWh). These estimates are produced by combining high-resolution (2-km) wind resource data (Maclaurin et al. 2014), hourly wind generation modeling for seven weather years using the System Advisor Model (Freeman et al. 2018), and high-spatial resolution (90-m) representation of excluded areas, with the wind turbine technology and cost assumptions described in Section 2.1.

In this analysis, we model setbacks and other exclusions for two siting regimes—Reference Access and Limited Access (based on Lopez et al. [2023] and summarized in Table 3). As noted in Table 3, some local ordinances apply height limits to turbines and setbacks to buildings and other infrastructure; these restrictions are typically based on maximum tip heights (Lopez et al. 2021). In general, larger turbines require larger setbacks and, thus, have less available land for installation. As described in Lopez et al. (2023), ordinances for wind energy vary by locality, and the quantity of ordinances for wind energy increased from 2018 to 2022. The siting regimes used here are based on a review of wind ordinances collected in 2022. If the growth of ordinances continues, siting exclusions could be more restrictive in the future.

[8] The LCOE is a single metric that combines the technology cost and performance assumptions (capital costs, OpEx, and capacity factor; refer to NREL [2023] for details on how LCOE is calculated).

Table 3. Overview of Siting Regimes[a]

Siting Exclusion Category	Siting Regime	
	Reference Access	*Limited Access*
Infrastructure		
Setbacks to transmission right of way, railroads, roads, building structures	General setback = 1.1x wind turbine tip height; structures = 2x wind turbine tip height	General setback = 2x wind turbine tip height; structures = 5x wind turbine tip height
Urban areas and airports	Excluded	Excluded
Radar	4-km NEXRAD; 9-km SRR/LRR	NEXRAD and SRR/LRR line of sight
Regulatory		
Documented state and county setback and height ordinances	Applied	Applied
Protected public lands and conservation easements	Excluded	Excluded
Other federal lands	Excluded	Excluded
Physical		
Slope	Excluded slope >25%	Excluded slope >13%
Mountainous landforms and high (>9,000 ft) elevation	Excluded	Excluded
Water and wetlands (with 305-m buffer)	Excluded	Excluded

Abbreviations: NEXRAD = Next Generation Weather Radar system operated by the National Weather Service, the Federal Aviation Administration, and the U.S. Air Force; SRR = short range radar; and LRR = long range radar.
a) Siting regime assumptions are based on Lopez et al. (2023).

2.2.1 Turbine Selection via Layout Optimization

Recent advancements to the reV model include the direct representation of individual turbine placements. Here, we use a previously developed optimization method that specifies the locations of individual turbines *within* each wind site (Stanley et al. 2022). This optimization weighs the increased wake losses of more closely spaced turbines with increasing BOS costs as turbines are spaced further apart (some limitations of this approach are discussed in the appendix). The reV model applies this geospatial optimization at all sites and discretely sites individual turbines to make up a wind power plant (Lopez et al. forthcoming). This optimization relies on the technology cost and performance assumptions, including the BOS economies of scale, defined through the wind technology and cost modeling (Section 2.1, Figure 2). The hourly generation profiles include the effects from intra-plant wake losses, which reduce plant capacity factors by 3–5 percentage points on average; this analysis does not consider inter-plant losses (e.g., wake effects from upstream plants on downstream plants). The least-cost optimization incorporates grid connection costs, including spur line costs and network grid reinforcement costs (see Gagnon et al. 2023 for details). These grid connection costs depend on the turbine and plant layout decisions because the voltage of the transmission infrastructure depends on the plant size (i.e., lower cost, higher voltage equipment is used for larger plants).

2.2.2 Individual and Composite Supply Curves

We use the reV model to develop supply curves for each of the four turbine technologies in Table 1. These supply curves characterize how the cost of wind energy varies for each turbine as the quantity of wind energy capacity increases. They incorporate the quality and quantity of wind energy resources that are available at each 11.5-km-by-11.5-km reV wind site across CONUS, including evaluating how much wind energy can be generated for a given turbine configuration under these conditions and assessing siting limitations based on state and local zoning ordinances. We also create a composite supply curve that comprises the least-cost choice (according to total LCOE) of each turbine at every location in CONUS. The result of the reV modeling process in our customized turbine choice methodology comprises five supply curves: four CONUS-wide supply curves representing each turbine technology individually and one CONUS-wide composite supply curve that includes multiple turbines with the least-cost turbine chosen at each location.

Because wind turbines tend to be tailored for specific wind resources, it is unlikely that turbines will be deployed in a location where the wind resource is not a good match for their design. As an example, lower specific-power turbines may not be covered under warranty in locations with high average wind speeds such as those found in the wind belt of the central United States. As a result, we implement wind speed thresholds specific to each turbine. The Low Wind 3.3 MW and Tall Tower 6.0 MW are restricted to locations with average wind speeds under 7.5 meters per second (m/s) while the Site Constrained 8.3 MW has a slightly higher wind speed threshold at 8.0 m/s. We do not assume any wind speed restrictions for the Standard 6.0 MW. Figure 3 demonstrates the extent of deployable area in CONUS for each wind turbine according to these thresholds and wind speed at their respective hub heights. The composite supply curve is created after filtering each supply curve to include only sites under the wind speed thresholds specific to each technology. At sites where there is only one remaining technology after the wind speed thresholds, that technology is chosen. This filtering is performed only as part of the composite supply curve.

Because of the high computational requirements associated with executing the reV model with plant layout optimizations at all sites in CONUS, we create supply curves for only one year: 2030. We use the supply curves from this single snapshot in time as an approximation of the technology choice at each location over all time when we perform the power sector modeling. As described in the next section, we do, however, allow the technology costs to vary over time in the power sector model. Although this assumption limits the spatial fidelity of our power sector modeling, it allows us to illustrate the overall modeling pipeline with achievable computational requirements. Future work could incorporate additional supply curves that capture change over time, which may reveal useful insights into the evolution of turbine siting as land constraints from increasing turbine sizes interact with falling costs, increasing efficiencies, and other factors.

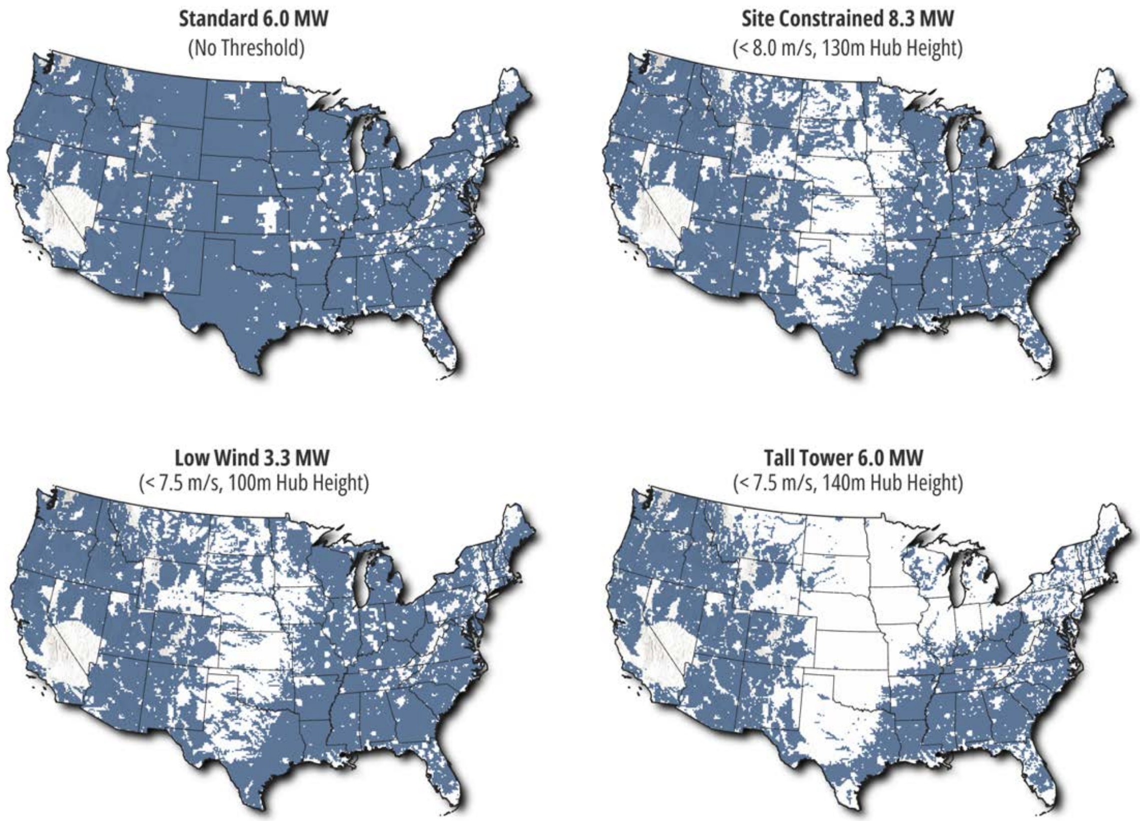

Figure 3. Extent of deployable potential for each turbine after wind speed thresholds are applied.

Blue coloring shows locations where each wind turbine is allowed to be deployed under the composite supply curve; areas in white are excluded based on the siting regime and the wind speed thresholds specific to each technology.

2.3 Power Sector Modeling

The final step in the composite turbine choice methodology involves performing power sector modeling to estimate future wind energy deployment based on the wind cost projections (Section 2.1) and wind energy supply curves (Section 2.2).

2.3.1 Technology Costs, Fuel Costs, and Grid Constraints

We use the Regional Energy Deployment System (ReEDS) (Ho et al. 2021; Mai et al. 2021; Gagnon et al. 2023) to estimate future wind energy deployment. ReEDS is a planning model for the CONUS power system that finds the optimal portfolio of generation, storage, and transmission to meet future grid and policy demands. ReEDS is unique in its representation of renewable energy technologies through its high spatial resolution and the way in which it reflects the variability and uncertainty of wind and solar technologies. Key outputs of the model include the regional capacity and generation from different technologies through 2050; however, our analysis here focuses on results through 2040. Key inputs of ReEDS include technology cost and performance over time, resource potential, and policy specifications.

In this analysis, the ReEDS inputs for wind energy technologies come from the technology and cost assumptions (Section 2.1) and the supply curves from the reV model (Section 2.2). The cost of other energy technologies, fuel costs, and grid constraints are based on default ReEDS assumptions (see Gagnon et al., 2023 for details). As described in Section 2.2, to reduce computational requirements for our demonstration of the composite turbine choice methodology, the supply curves in the analysis performed here do not change over time; they are representative of a single snapshot in time (2030). This simplifying assumption could be revisited in future work. Technology cost and performance improvements over time are incorporated within ReEDS and are taken directly from Section 2.1; however, regional variations in capital costs are modeled in ReEDS—so not all locations will have the same "typical" plant costs listed in Table 1. Capacity factor improvements, including reductions in losses, are modeled by scaling up the hourly generation profiles. The data ingested in ReEDS from the reV supply curves include the resource potential, hourly capacity factor, and grid connection costs for each of the 11.5-km-by-11.5-km wind sites. The data for the ~50,000 reV sites are aggregated into 6,600 available investment options—up to 10 capacity factor classes and 10 cost bins for each of the 134 model regions—in ReEDS.[9]

2.3.2 Power Sector Analysis Scenarios, Including Energy Policy Assumptions

For this analysis, we use ReEDS to examine wind deployment estimates and metrics related to wind's estimated economic viability by location. Because these estimates differ depending on future conditions, we examine five scenarios of the U.S. electricity system through 2040 (Table 4).

Table 4. Power Sector Analysis Scenarios

	Power Sector Analysis Scenario				
	Reference	*Limited*	*Advanced*	*Conservative*	*Low Carbon*
Cost scenario (Section 2.1)[a]	Moderate	Moderate	Advanced	Conservative	Moderate
Siting regime (Section 2.2)[a]	Reference Access	Limited Access	Reference Access	Reference Access	Reference Access
Power sector emissions scenario	Reference	Reference	Reference	Reference	Low Carbon

a) As noted in Section 2.2, because of the high computational requirements associated with executing the reV model with plant layout optimizations at all sites in CONUS, we create supply curves for technology costs from only one scenario at a single point in time (moderate turbine cost scenario in 2030). However, within the power sector model, we allow the cost trajectory for each turbine technology to change over time based on the cost scenarios outlined in Section 2.1.

The Reference power sector analysis scenario uses the wind costs from the Moderate cost scenario (see Section 2.1 for details), the Reference Access siting regime (see Table 3), and Reference power sector emissions policies. The Reference power sector emissions scenario includes state and federal policies as of June 2023, including the Inflation Reduction Act.[10] The

[9] Unique hourly profiles are modeled for each region class. The cost bins include interconnection and transmission reinforcement costs, economies of scale adders, regional adjustments to account for labor rates, and land lease costs.
[10] The Inflation Reduction Act includes a 10-year $29/MWh production tax credit for land-based wind through 2032 or after annual electricity sector emissions are below ~400 million metric tons of carbon dioxide (25% of 2022

Limited scenario uses the same wind turbine cost and power sector emissions scenarios, but it assumes a Limited Access siting regime as defined in Table 3. The Advanced and Conservative power sector analysis scenarios assume a Reference Access siting regime and Reference power sector emissions scenario but use the Advanced and Conservative wind turbine cost scenarios, respectively. Finally, the Low Carbon power sector analysis scenario assumes a Moderate turbine cost scenario and Reference Access siting regime but includes the combination of a limit on power sector emissions (~83% reduction from 2005 levels by 2040) and high demand growth consistent with electrification under an economywide net zero by 2050 emissions trajectory from the Central case of the 2022 Annual Decarbonization Pathway study (Haley et al. 2022). Other assumptions are based on NREL's Standard Scenarios 2023 Mid-case (Gagnon et al. 2023).

The five scenarios shown in Table 4 are modeled for all four turbine configurations (Table 1) individually and for a composite supply curve developed based on the least-cost turbine at each location. The next section compares the supply curve and estimated wind deployment results when these individual turbines are applied uniformly across the United States and explores how turbine choice assumptions could impact the wind supply curve and deployment outcomes.[11]

levels), whichever is later. This emissions threshold is not met by 2040 in any of our scenarios thus the tax credit persists throughout the study horizon.

[11] In Section 3, all results using the "individual" turbines do not apply any wind speed thresholds; i.e., the turbine is assumed to be deployable in all locations. However, the composite supply curve uses wind speed thresholds when selecting the turbine in each location as described in Section 2.2.

3 Results

In this section, we apply our customized turbine choice methodology to explore how a composite turbine scenario—comprising a collection of the four different turbines chosen on a least-cost basis at each location with wind speed thresholds (see Section 2 for details)—can result in different future wind deployment estimates compared to scenarios that assume a single uniform turbine option in all locations.[12] We explore these results in two sections: the first section explores changes in the supply curves and the second section evaluates how wind energy deployment projections vary based on these composite supply curves. It important to note that these results are based on future estimates of cost and performance assumptions that are anticipated to occur by 2030 (see Section 2.1) and are intended to reflect future conditions as the industry continues to evolve and innovate. Alternative cost and performance assumptions (e.g., different base year; incorporation of additional supply chain or logistical constraints that are not modeled here) could modify the composition and performance of the composite supply curve. As discussed further in Section 4, future work is needed to assess the implications of this methodology.

3.1 Comparison Between Individual and Composite Supply Curves

We find that the technology configurations, costs, and siting constraints interact to modify the wind energy supply curves and thereby inform the potential national deployment metrics for each turbine across CONUS (Figure 4). These metrics include the total amount of developable area available for deployment, the total number of turbines and the total capacity that could be constructed, and the annual energy production (AEP) that could be generated if that turbine technology were deployed in all developable land area across CONUS. Because siting constraints modify turbine placement, the amount of developable area, number of turbines, and associated wind energy performance metrics (e.g., capacity as well as annual energy production) vary by turbine and siting regime. For example, Low Wind 3.3 MW has the most developable area available because it has the lowest hub height and therefore has fewer setback constraints. However, even though more turbines could be deployed for the Low Wind 3.3 MW, the overall capacity and annual energy production are lower because the turbine rating is the lowest of all technologies. Furthermore, under the Limited Access siting regime, all turbine technologies have less land available for deployment—therefore, fewer turbines can be placed, the total installed capacities are lower, and the AEP is reduced. However, variations across turbines under Limited Access are smaller than under Reference Access as development is significantly constrained for all turbine options.

[12] All results presented using the "individual" turbines do not apply any wind speed thresholds; i.e., the turbine is assumed to be deployable in all locations. However, the composite supply curve uses wind speed thresholds when selecting the turbine in each location as described in Section 2.2.

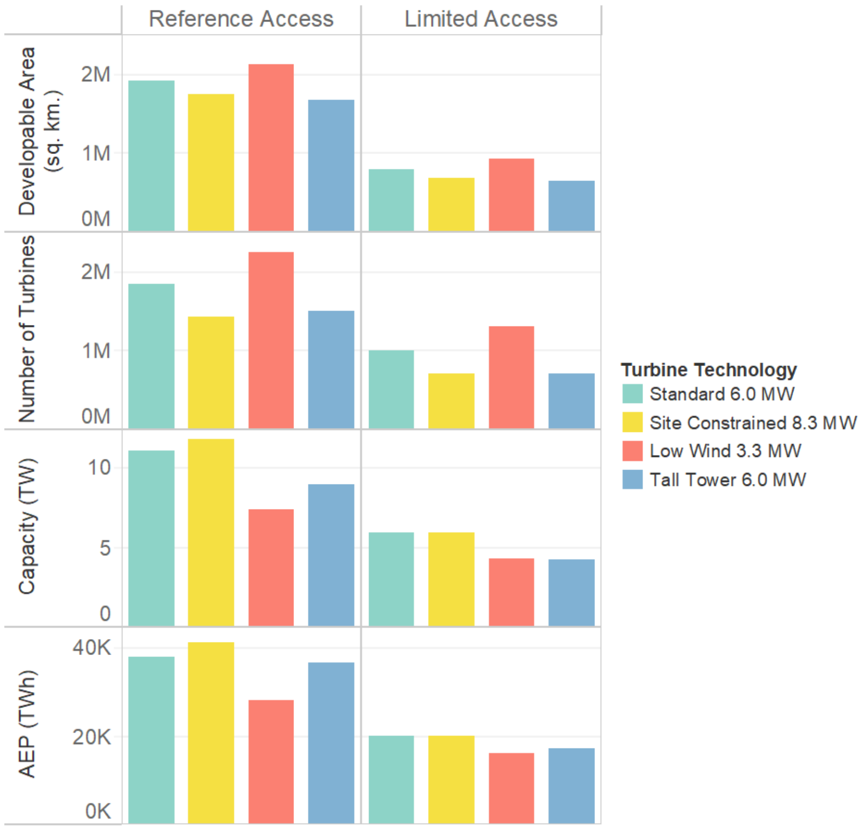

Figure 4. Comparison of potential national deployment metrics for each of the four turbines under the Reference Access and Limited Access siting regimes.

As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

We also show that differences between the individual supply curves (without wind speed thresholds) and the composite supply curve, which includes wind speed thresholds, vary by technology (Figure 5; see the appendix for Figure A-4, which illustrates individual supply curves with wind speed thresholds). Costs are within $20/MWh to $40/MWh across all turbines for the first 4 terawatts[13] (TW) (see inlay of Figure 5). These narrow differences at the low end of the supply curve reflect the large amount of U.S. land with high-quality wind resource and the cost improvements that are realized through turbine scaling (Section 2.1). Differences between the turbines are most apparent toward the higher end of the supply curves. The larger differences at the higher end of the supply curve reflect the interactions between BOS scaling, wake losses, and siting exclusions across the various turbines. For example, larger turbines have larger setbacks and more spacing requirements and therefore more land area constraints. However, the larger capacities associated with these larger machines could enable more MW of potential while taller towers and larger rotor diameters can yield higher energy capture. These interactions are further complicated by the wake effects and economies of scale considered in the LCOE-based plant layout optimization (refer to Lopez et al. [forthcoming] for more details).

[13] Achieving U.S. decarbonization goals could require a total installed capacity of approximately 1 TW of wind energy by 2035 (Denholm et al. 2022).

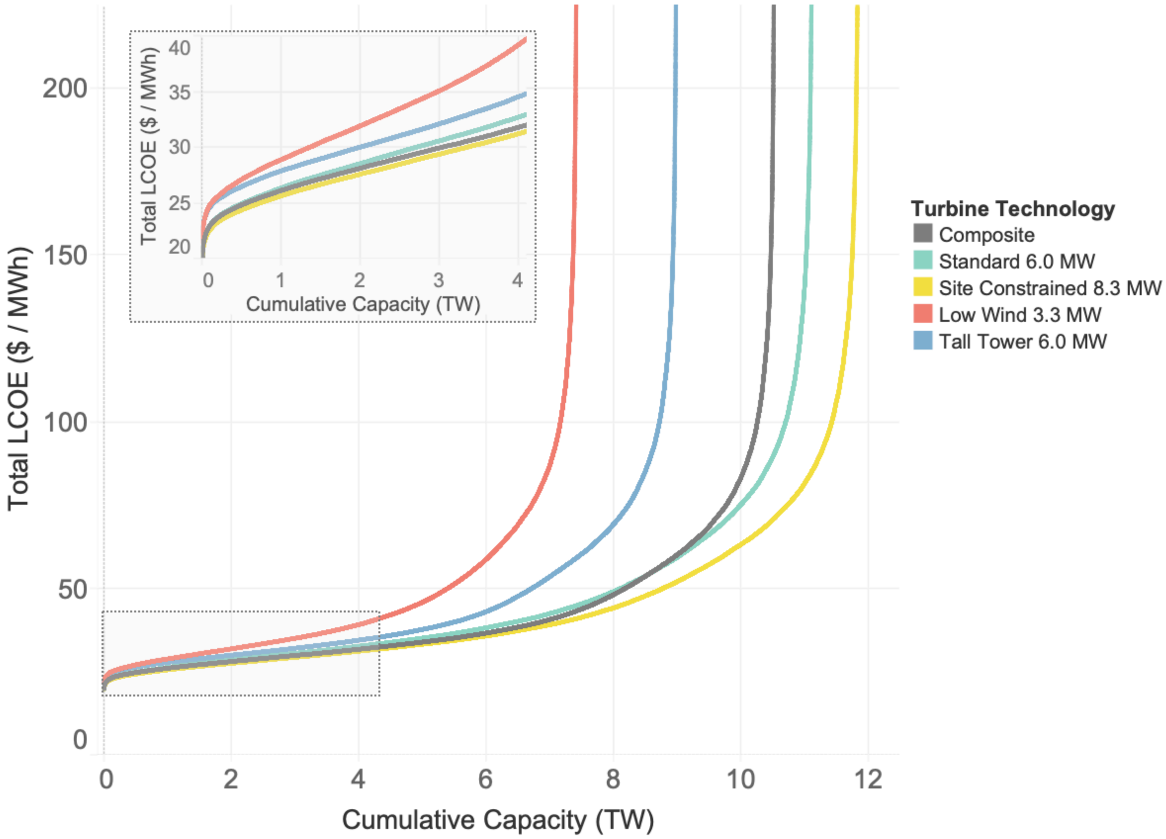

Figure 5. Supply curves for each individual turbine (no wind speed thresholds) compared to the composite (including wind speed thresholds) for the Reference Access siting regime and Moderate turbine cost scenario in 2030.

The inlay shows how the supply curves differ at lower cumulative capacities (from 0 TW to 4 TW). As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D. See the appendix for Figure A-4, which illustrates the supply curves for individual turbines with wind speed thresholds applied.

Under our baseline supply curve scenario (Reference Access siting regime and Moderate turbine cost scenario in 2030), turbine technology choice for the composite varies by location, with the Standard 6.0 MW dominating in the Interior, taller towers (Site Constrained 8.3 MW and Tall Tower 6.0 MW) mostly chosen in the Southeast, and Low Wind 3.3 MW deployed in a limited number of small areas in the West (Figure 6). In this scenario, the Site Constrained 8.3 MW comprises about the largest portion of the composite (43% of the total capacity of the composite; 37% of the composite by the count of sites), followed by the Standard 6.0 MW (29% of the capacity; 25% of the count of sites), Tall Tower 6.0 MW (22% of the capacity; 29% of the count of sites), and Low Wind 3.3 MW (6% of the capacity; 8% of the count of sites) for this scenario. The Standard 6.0 MW and the Site Constrained 8.3 MW are the preferred choices in large fractions of the Interior because of their higher specific powers and low per-unit capital costs. In addition, the Standard 6.0 MW is not restricted by the wind speed thresholds faced by the other turbines while the thresholds assigned to the Site Constrained 8.3 MW allow for significantly more capacity in the Great Lakes and Northeast regions than the Tall Tower 6.0 MW.

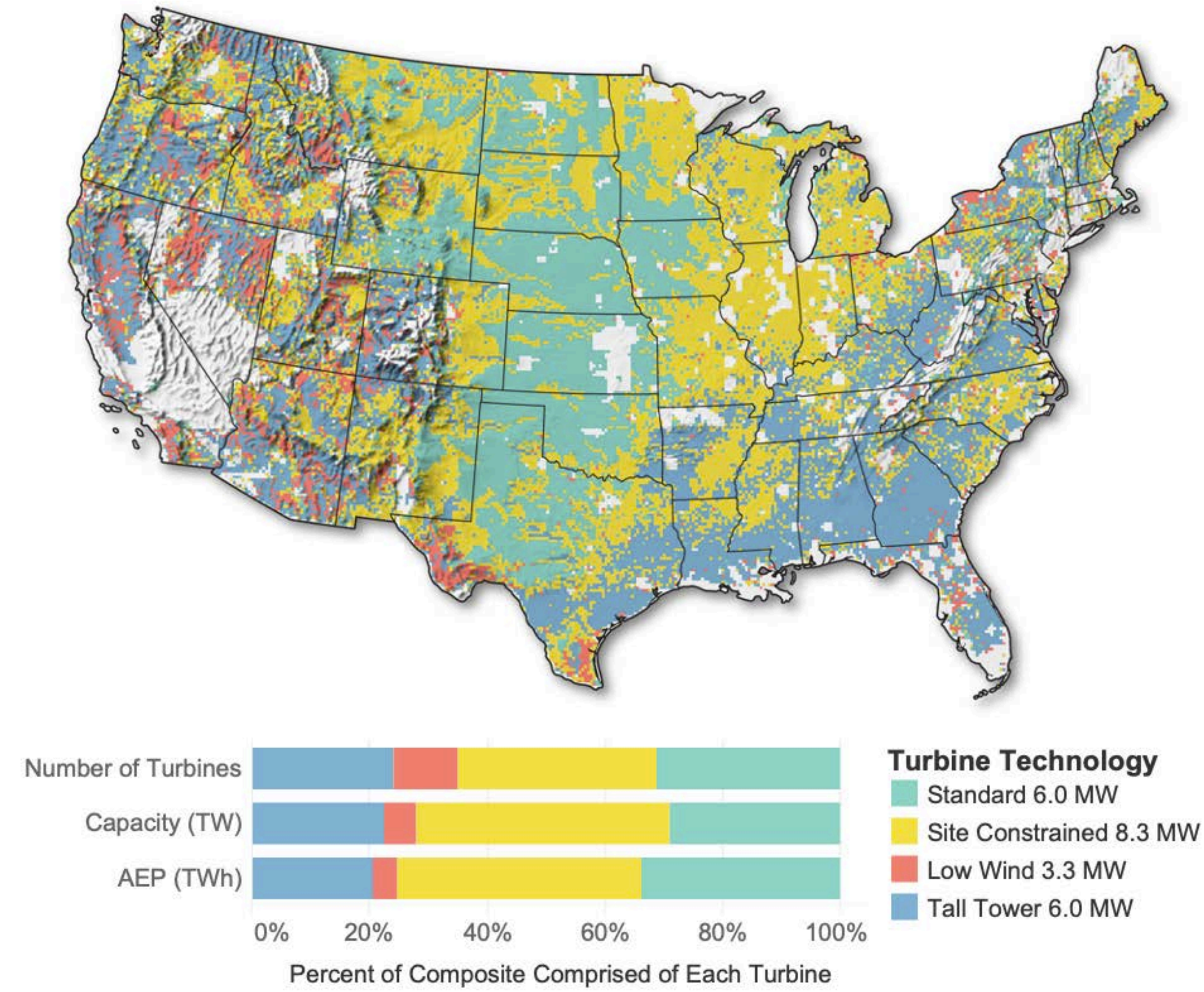

Figure 6. Turbines chosen for the composite under Reference Access siting regime and the Moderate turbine cost scenario in 2030.

As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

Map by Billy Roberts, NREL.

It is important to note that these results are specific to the technology configurations and cost trajectories that are assumed here. As described in Section 2.1, our estimates of future cost and performance assumptions are intended to reflect future conditions as the industry continues to evolve and innovate. For example, our turbine configurations and estimated costs assume that a series of innovations (i.e., on-site manufacturing, spiral-welded towers, alternative erection technologies, segmented blades, and controls advancements) can reduce transportation challenges and improve the performance of next-generation wind turbines by 2030. Furthermore, not all our modeled configurations are currently available on the market. However, turbines that are nearly of this scale are commercially available now and are expected to be installed at select sites in the United States in the 2020s. Alternative turbine configurations and cost assumptions (e.g., alternative timelines for technology evolution, smaller turbines, limited innovations, or different logistical constraints) would modify the composition of the composite supply curve.

Figure 7 shows the LCOE for the composite supply curve under the Reference Access siting regime and the Moderate turbine cost scenario in 2030. The average LCOE across all sites is $46/MWh but with significant variations between locations; e.g., LCOEs in many locations in the West and Northeast are higher because of lower wind resource quality and higher interconnection costs.

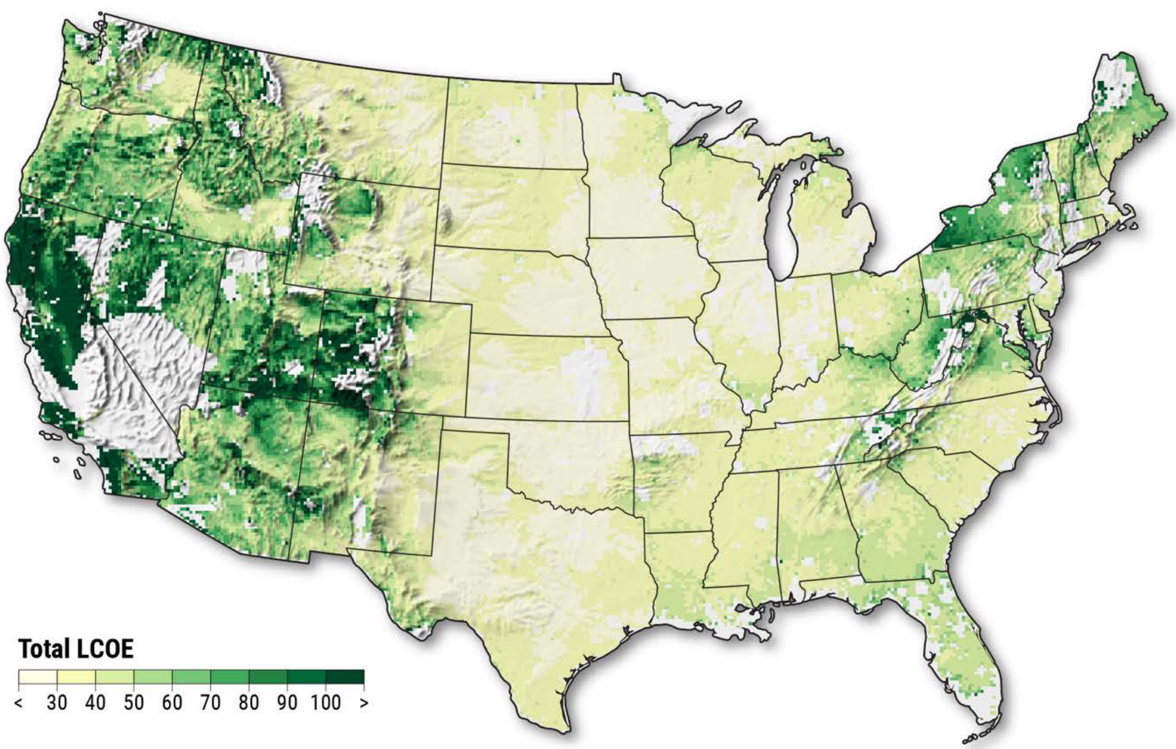

Figure 7. Total LCOE ($/MWh) for the composite supply curve based on the Reference Access siting regime and the Moderate turbine cost assumptions in 2030

Illustration by Billy Roberts, NREL.

Under our baseline scenario (Reference Access siting regime and Moderate cost scenario in 2030), we find that developing a composite supply curve comprised of multiple turbine configurations with the least-cost option chosen at each location as opposed to using a single turbine technology does not have much impact on LCOE, but it does modify total capacity potential and annual energy production (Figures 8 and 9). When each individual turbine supply curve is compared to the composite supply curve, the average total LCOE[14] of the individual turbine supply curves is 0.5% to 5.5% higher than the composite (Figure 8) and the differences vary slightly by location (Figure 9). The differences in annual energy production and capacity are larger and vary more by location and by technology (compared to the composite, individual turbines have -29% to 13% differences in capacity and -27% to 6% differences in AEP; Figure 8). The Low Wind 3.3 MW turbine is the most different from the composite, with 29% less total capacity, 27% lower total AEP, and 5.5% higher average LCOE compared to the composite (Figure 8). The Site Constrained 8.3 MW turbine has 13% greater total capacity and 6% higher

[14] Total LCOE equals the LCOE ($/MWh) plus the levelized cost of transmission (LCOT; $/MWh) at a given wind site. Average total LCOE is the average of all the site-specific total LCOEs across the entire supply curve (or across all locations in CONUS).

total AEP than the composite, but it also has an average LCOE that is 1.1% higher than the composite (Figure 8).

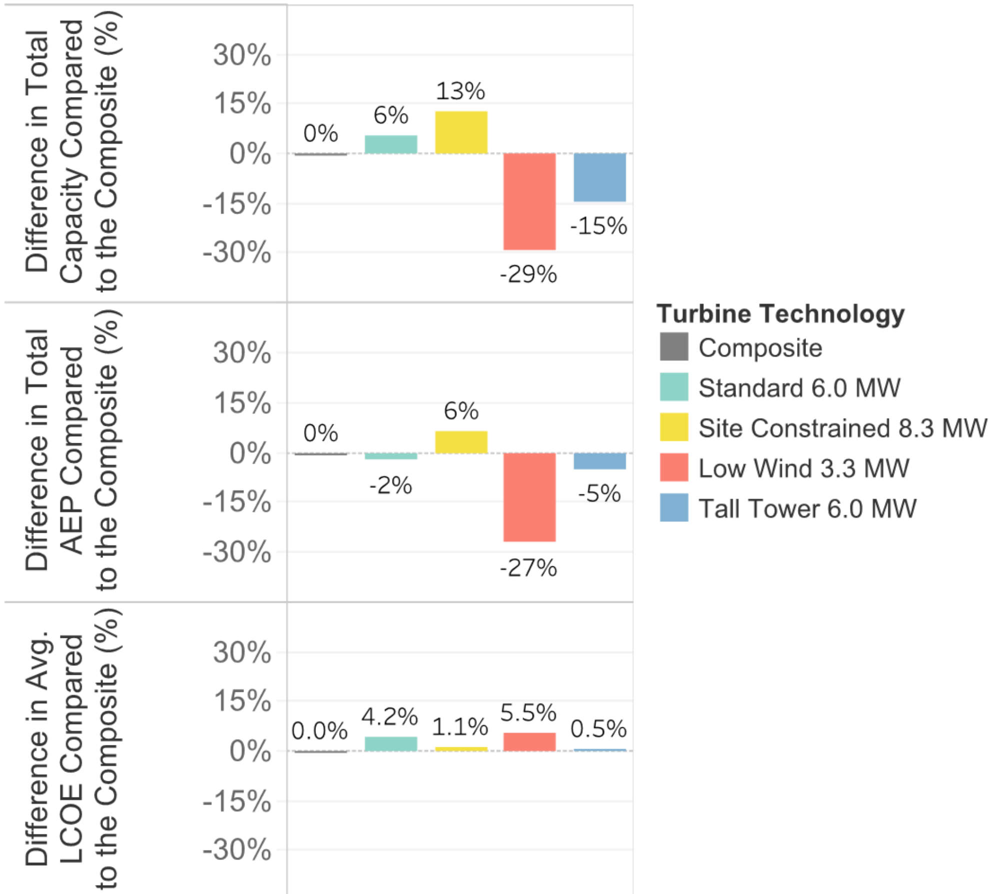

Figure 8. Differences in average capacity, AEP, and total LCOE for Reference Access siting regime under the Moderate turbine cost scenario in 2030.

As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

These differences are even more pronounced in certain regions for each technology (Figure 9). For example, the Standard 6.0 MW and Site Constrained 8.3 MW have larger differences than the composite in the Southeast and West, whereas Low Wind 3.3 MW and Tall Tower 6.0 MW are more different from the composite in the Interior region of the United States. These differences are explained by the choice of the least-cost turbine in the composite (Figure 6), where the Standard 6.0 MW and Site Constrained 8.3 MW are mostly chosen in the Interior region and the Low Wind 3.3 MW and Tall Tower 6.0 MW turbines are mostly chosen in the Southeast and West. This choice of least-cost turbine is informed by both the LCOE of the turbine and wind speed thresholds (Figure 3). For example, in a large portion of the Interior, the Standard 6.0 MW turbine is the only turbine that is available based on the wind speed thresholds. From a cost perspective, the Site Constrained 8.3 MW has a high specific power and larger turbine rating, which make it more cost competitive in areas with more land constraints. The Low Wind 3.3 MW has a low specific power, which presents advantages in areas with lower wind resource. The Tall Tower 6.0 MW has a low specific power and taller tower, which is most competitive in areas that have relatively poor wind resources at ~100 m above ground but greater average wind speeds at higher hub heights (e.g., the Southeast).

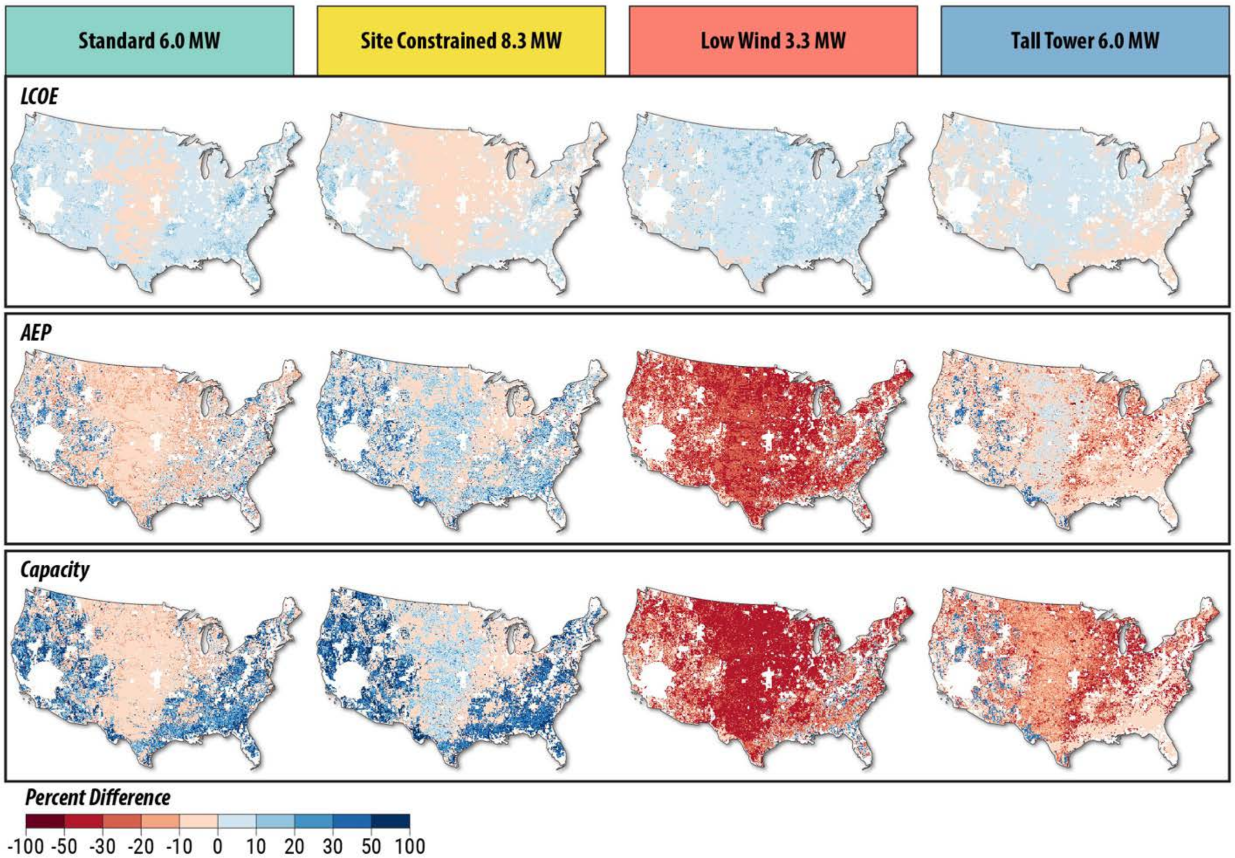

Figure 9. Differences in capacity, AEP, and LCOE compared to the composite turbine scenario with Reference Access siting regime and Moderate turbine cost scenario in 2030.[15]

As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site-Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low-Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

Illustration by Billy Roberts, NREL.

3.2 Impact on Wind Energy Deployment Projections

When we implement the composite supply curve in our power sector model—ReEDS—we find that the Limited scenario generates about ~200 GW less wind capacity than the Reference scenario, and the Conservative scenario is ~300 GW less than the Advanced scenario (Figure 10; see Table 4 for details about scenario definitions). The primary differences in generation occur for wind and solar, which are projected to grow to 25%–46% and 20%–32%, respectively, by 2040 (using the composite), compared with 10% and 3% today (U.S. Energy Information

[15] Because we only apply wind speed thresholds to the composite supply curve, individual turbine supply curves can have locations with lower LCOE than the composite. For example, in a large portion of the Interior, the Standard 6.0 MW turbine is the only turbine that is available based on the wind speed thresholds. However, the Site Constrained 8.3 MW has a high specific power and larger turbine rating, which, in certain locations, results in a lower LCOE compared to the composite.

Administration 2023). Under the Low Carbon scenario, this growth is even greater in absolute terms because of the high electrification assumption. The Reference, Limited, Conservative, and Advanced scenarios are all quite similar, but there are some larger increases in generation in the Low Carbon scenario after 2030.

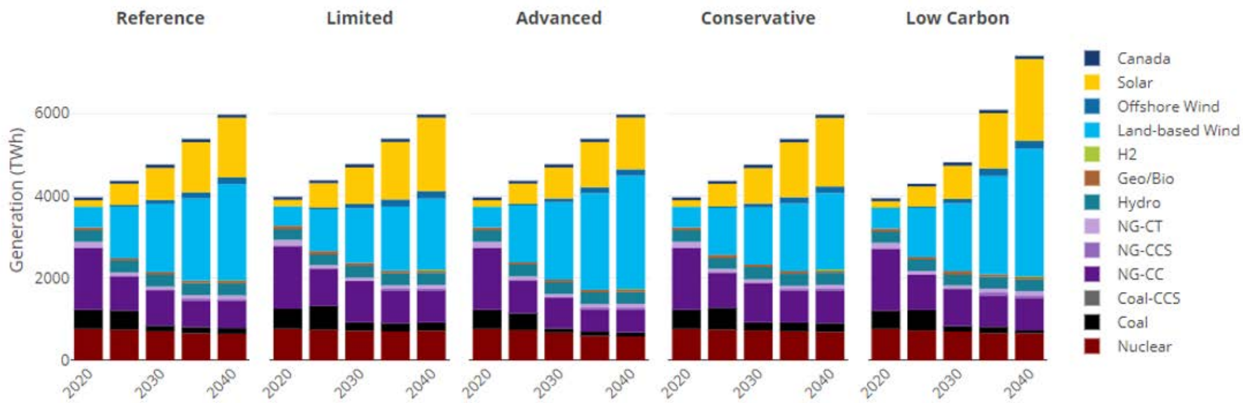

Figure 10. Generation over time for all energy technologies as calculated by ReEDS using the wind turbine composite supply curve.

Abbreviations: H2 = hydrogen (combustion turbine), Geo/Bio = geothermal and biopower; Hydro = hydropower; NG-CT = natural gas combustion turbine; NG-CCS = natural gas combined cycle with carbon capture and sequestration; NG-CC = natural gas combined cycle; Coal-CCS = coal with carbon capture and sequestration.

However, when we look at the generation fraction by technology for a single year (2040) and compare each individual technology to the composite (Figure 11), we see that there are some small differences in which technologies get chosen. In all power sector modeling scenarios, the generation fraction that comprises land-based wind is 1% to 5% less when individual turbines are used compared to a composite supply curve. In most scenarios, this generation is replaced by solar followed by natural gas with smaller differences in coal, nuclear, and offshore wind.

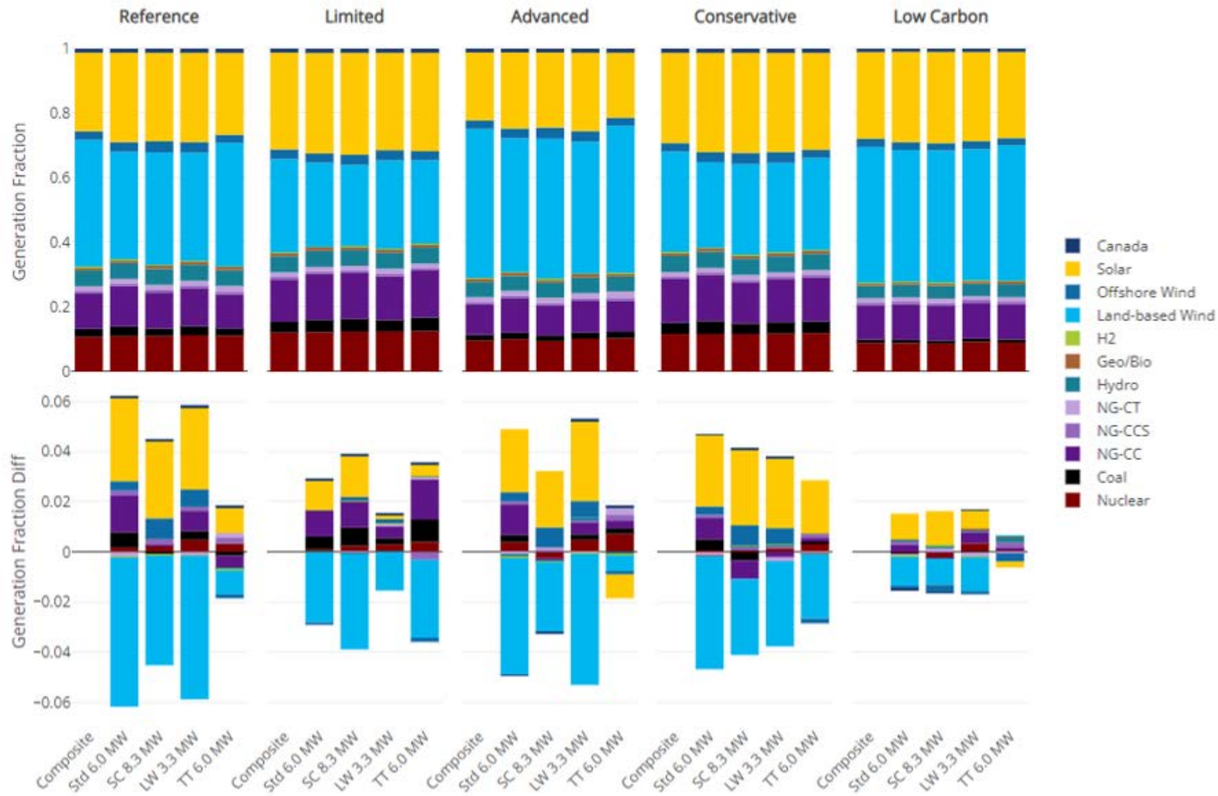

Figure 10. Generation fraction by technology (top row) and difference in generation fraction compared to the composite (bottom row) for single wind turbine technologies and the composite in 2040.

Abbreviations: H2 = hydrogen (combustion turbine), Geo/Bio = geothermal and biopower; Hydro = hydropower; NG-CT = natural gas combustion turbine; NG-CCS = natural gas combined cycle with carbon capture and sequestration; NG-CC = natural gas combined cycle; Coal-CCS = coal with carbon capture and sequestration; Std = Standard; SC = Site Constrained; LW = Low Wind; TT = Tall Tower.

The total installed capacity varies by scenario and within each scenario when using a single wind energy technology versus the composite (Figure 12). For the Standard 6.0 MW and Site Constrained 8.3 MW in the Advanced and Low Carbon scenarios, we find that the land-based wind capacity of the individual turbines is larger. However, for all other cases, the capacity of the individual turbines is smaller than the capacity of the composite supply curve. This decrease in land-based wind capacity is usually displaced by an increase in storage, solar, and natural gas combined cycle.

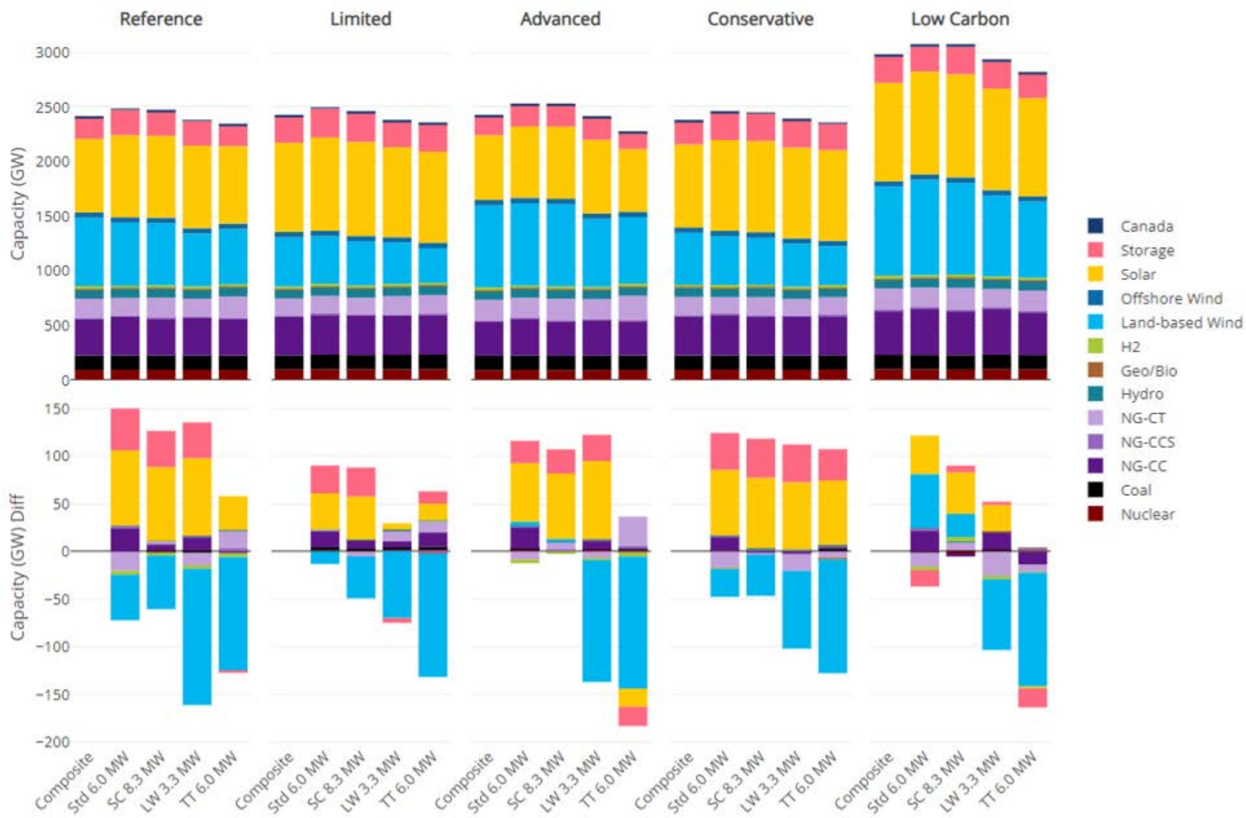

Figure 11. Absolute capacity (top row) and differences in capacity compared to the composite (bottom row) for single wind turbine technologies and the composite in 2040.

Abbreviations: H2 = hydrogen (combustion turbine), Geo/Bio = geothermal and biopower; Hydro = hydropower; NG-CT = natural gas combustion turbine; NG-CCS = natural gas combined cycle with carbon capture and sequestration; NG-CC = natural gas combined cycle; Coal-CCS = coal with carbon capture and sequestration; Std = Standard; SC = Site Constrained; LW = Low Wind; TT = Tall Tower. As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

If we examine changes to land-based wind alone, we see that the composite usually results in more capacity over time compared to a single turbine (Figure 13). However, there are a few cases—particularly before 2030 and in the Low Carbon scenario—where the Standard 6.0 MW and Site Constrained 8.3 MW have more land-based capacity than the composite. The individual turbines could outperform the composite because they do not have wind speed thresholds applied or because the least-cost choice of turbine in the composite does not account for other aspects of performance (e.g., generation over time) that are incorporated in the power sector modeling. However, when we look at generation, we see that even in cases where the capacity of an individual technology might be greater than the composite supply curve, the generation produced by the composite outperforms that of the individual turbines.

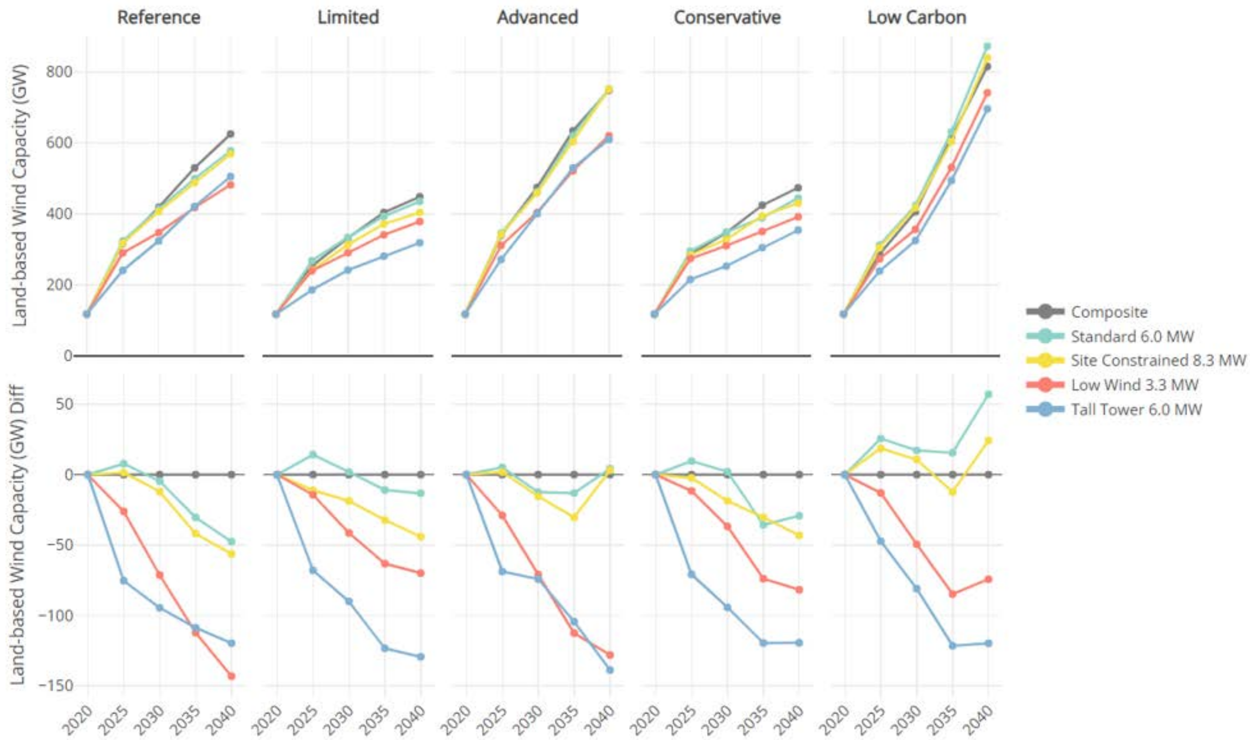

Figure 12. Absolute capacity of land-based wind technologies (top row) and differences in capacity of land-based wind technologies compared to the composite (bottom row) for single wind turbine technologies and the composite in 2040.

As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

The benefit of using a composite supply curve compared to individual turbine technology varies by scenario (Figure 13; Table 5). We find that using our composite supply curve increases estimated land-based wind capacity by 8%–23% (48–143 GW) and generation by 3%–15% (59– to 340 terawatt-hours [TWh]) in the Reference scenario in the year 2040. In addition, using a composite supply curve changes the estimated power system cost by -2.5% to +1.4% (-$73 to $40 billion) and power sector carbon dioxide emissions by -14% to +3% (-73 to 40 million tonnes) in the Reference scenario in 2040. In all the scenarios we examined here, the composite resulted in more generation from land-based wind in 2040 compared to when a single individual turbine is modeled. However, in some cases (e.g., before 2030 and in the Low Carbon scenario), the land-based wind capacity of the composite is lower and power system cost and electric sector carbon-dioxide emissions increase (see Figure 13 and Table 5; Figure A-5 illustrates the differences in system cost). In the Low Carbon scenario, generation differences in 2040 between all turbine options—composite and any of the four individual turbines—are small (<100 TWh for any technology). This is likely because of high demand for wind generation irrespective of turbine assumption, in this case with high electrification and a cap on grid emissions.

Table 5. Power Sector Performance Metrics for the Reference Scenario in 2040

		Composite	Standard 6.0 MW	Site Constrained 8.3 MW	Low Wind 3.3 MW	Tall Tower 6.0 MW
Capacity of land-based wind	*GW*	625	577	569	482	505
	Difference relative to composite	n/a	-8%	-9%	-23%	-19%
Generation from land-based wind	*TWh*	2,341	1,987	2,079	1,999	2,282
	Difference relative to composite	n/a	-15%	-11%	-15%	-3%
Total power system costs (all energy technologies)	*billions of $*	2,884	2,958	2,886	2,885	2,844
	Difference relative to composite	n/a	2.5%	0.1%	0.0%	-1.4%
Total electric sector carbon dioxide emissions	*million tonnes of carbon dioxide*	448	509	443	482	432
	Difference relative to composite	n/a	14%	-1%	8%	-3%
Electricity price	*$/MWh*	50.9	52.5	50.8	52.5	51.6
	Difference relative to composite	n/a	3.0%	-0.3%	3.0%	1.3%

Abbreviations: n/a = not applicable.

These results indicate that using a composite supply curve could lead to higher estimates for wind potential and future deployment. This finding suggests that customizing wind turbine choice in capacity expansion models could lead to higher estimates of wind energy deployment. It also suggests that more simplified modeling might underestimate the role of wind and the extent of decarbonization in the future.

4 Conclusions and Future Research

We developed a customized turbine choice methodology that integrates wind energy cost modeling, supply curve modeling, and power sector modeling to incorporate turbine-specific cost and technology representations of four distinct wind turbines into a composite supply curve. This approach involves modeling the placement of individual turbines at the plant level, including accounting for land use, wake losses, and BOS economies of scale. The inclusion of bottom-up cost modeling allows us to assess cost trade-offs between turbine options. We applied this methodology to evaluate how turbine choice could change the wind supply curve and modify future deployment estimates.

From a supply curve perspective, we found that in our baseline scenario (Reference Access siting regime and Moderate cost scenario in 2030) the differences in the average total LCOE between the single turbines and the composite supply curve are less than 6% and do not vary much by location, but the absolute differences in annual energy production and capacity are larger (5% to 29%) and vary by location and technology. These differences are even more pronounced in certain regions based on the choice of the least-cost technology at each location (e.g., the Standard 6.0 MW and Site Constrained 8.3 MW have larger differences compared to the composite in the Southeast and West, whereas Low Wind 3.3 MW and Tall Tower 6.0 MW are more different from the composite in the Interior region of the United States).

We implemented these supply curves in our power sector model and explored how deployment estimates changed under five power sector analysis scenarios: Reference, Limited, Conservative, Advanced, and Low Carbon (see Section 2.3 for details). In all scenarios, the composite resulted in more generation from land-based wind in 2040 compared to when a single individual turbine was modeled. However, in some cases (e.g., before 2030 and Low Carbon), the land-based wind capacity of the composite was lower, and the power system cost and electric sector carbon-dioxide emissions increased. In the Reference scenario, using the composite supply curve increased estimated deployment of land-based wind capacity by 8%–19% (48–143 GW) and generation by 3%–15% (59–340 TWh) in the year 2040. Our findings indicate that customizing wind turbine choice in capacity expansion models could lead to higher estimates of wind energy deployment and better capture the role wind energy could play in supporting decarbonization efforts.

There are several limitations of our approach. For example, our results are specific to the technology configurations and cost trajectories that are assumed here. As described in Sections 2.1 and 2.2, the supply curves that we feed into our capacity expansion model are based on one set of future estimates of cost and performance assumptions that are anticipated to occur by 2030 (Moderate cost scenario in 2030). Therefore, our results are intended to reflect future conditions as the industry continues to evolve and innovate. Alternative cost and performance assumptions (e.g., different base year; incorporation of additional supply chain or logistical constraints that are not modeled here) would modify costs of turbine technologies and could result in a single turbine performing better than a composite supply curve. Furthermore, we consider only four turbine configurations, and we impose wind speed cutoffs as a proxy for evaluating each turbine's suitability at a given site. There are other turbine configurations and site suitability criteria that could be considered. We also examine only a narrow set of power sector scenarios; other scenarios might yield different results.

In addition, we explore only one approach for our wind turbine placement optimization: cost based. This selection criterion does not consider any differences in grid value between the turbines,[16] and it does not capture futures where wind energy (or energy from other low-emissions sources) is more constraining than costs. A value- or energy-informed optimization method could incorporate these considerations,[17] and future work could explore how such an approach might modify the benefits of our customized turbine choice methodology. Finally, explicitly representing turbine selection within the capacity expansion model may be a better method in principle. Such a method would enable the turbine selection to occur dynamically depending on future demand for wind, system needs, and price (and price profiles) for grid services. However, implementing this method is computationally expensive, especially if the same level of detail is modeled for the multiple turbine options. Future work is needed to explore the feasibility of implementing this approach.

Our initial analysis of the new customized turbine choice methodology reveals that using a composite supply curve in power sector models could expand opportunities for competitive wind deployment in the United States and lead to higher estimates of future wind energy deployment. Our results also indicate that more simplified modeling might underestimate the role of wind in meeting decarbonization goals. However, future work is needed to further explore the implications of turbine choice, including examining alternative approaches (e.g., incorporating value- or energy-informed optimization, explicitly modeling turbine selection within capacity expansion models, exploring other cost and performance assumptions and power sector emission scenarios). Future work could also consider how social and environmental pressures, or other factors, might drive local or regional areas towards one turbine configuration over another. Such information could help inform the technology researchers, original equipment manufacturers, and other wind industry stakeholders about the market potential of different wind turbine technologies.

[16] Each turbine has a different wind generation profile because of differences in wind resource (at different hub heights) and power curves. As a result, the value each turbine could provide to the grid or, alternatively, the revenue they could receive from providing various grid services could differ.

[17] For example, the capacity credit—defined as the fraction of the power plant's capacity that contributes to planning reserve or other resource adequacy requirements—for wind can differ depending on the generation profiles. The ReEDS capacity expansion model estimates these contributions and other sources of value, along with the capital and operating costs, of the full suite of technology options to determine the systemwide least-cost portfolio. These metrics could be used to inform the turbine selection criteria to develop value-informed composite supply curves.

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Appendix

Details on Wind Turbine Technology Cost Modeling

As described in the main text, we model four different near-future turbines: Standard 6.0 MW, Site Constrained 8.3 MW, Low Wind 3.3 MW, and Tall Tower 6.0 MW. Table A-1 compares the characteristics of each of the modeled turbines with a 2021 market average turbine.

Table A-1. Comparison to Market Average Turbine

Parameter	2021 Market Average Turbine	Standard 6.0 MW	Site Constrained 8.3 MW	Low Wind 3.3 MW	Tall Tower 6.0 MW
Turbine rating (megawatts [MW])	3.0	6.0	8.3	3.3	6.0
Rotor diameter (meters [m])	128	170	196	148	196
Specific power (watts per square meter [W/m^2])	235	264	275	192	199
Hub height (m)	94	115	130	100	140

Updates to the Cost and Scaling Model

We made several updates to National Renewable Energy Laboratory's Cost and Scaling Model (CSM) to better capture current and future turbine technology. The updated curve fits for the turbine components are listed in Table A-2 and are summarized as follows:

- We developed component mass and scaling relationships for 2021 using empirical component masses from original equipment manufacturer (OEM) documentation from 2.5 megawatts (MW) to 6.6 MW and included GE, Vestas, Nordex, and SGRE.
- We based component mass scaling relationships for 2030 on 2021 empirical component masses and modified the CSM to incorporate the following turbine innovations (i.e., on-site manufacturing, spiral-welded towers, alternative erection technologies, and segmented blades) and controls advancements (reducing component loads, masses, and costs).
    - On-site manufacturing and spiral-welded towers: We assume advances in tower manufacturing for towers manufactured in factories and through on-site manufacturing. We based our tower mass and scaling relationships on Keystone Tower Systems (KTS) tower designs for a range of turbine ratings and hub heights that were presented as part of the U.S. Department of Energy (DOE) tall tower funding opportunity announcement (FOA). The KTS technology uses a novel, highly automated spiral-welding process that reduces tower cost compared to conventional towers. We assume that towers less than 120-m hub height are

produced in factories and towers greater than 120-m hub height are manufactured on-site.

- Alternative erection technologies: As turbine rating, hub height, and blade length increase, the cost of conventional crawler cranes increases rapidly (Key, Roberts, and Eberle 2021). We assume that alternative erection concepts such as climbing cranes[18] may decrease the cost of erection, relative to conventional erection, especially as turbine hub height and rating increase.[19]

- Segmented blades: We assume segmented blades to reduce transportation and logistics challenges and costs. Blade segmentation adds mass and cost to the blade but for blades greater than 70–80 m in length, the increased cost of segmentation may be cost effective.

- Controls advancements: We assume load reduction because of advanced controls, which affects nearly all components in the drivetrain, nacelle structure, and tower. Within the turbine, we assume reductions in mass for the following components: blades (mentioned previously), hub, nacelle bedplate, low-speed shaft, gearbox, main bearings, and generator. For example, mass reductions are based on industry projections for higher torque density for gearboxes. We also assume reductions in blade mass and cost are achieved through advanced manufacturing.

Inputs for Land-based Balance-of-System Systems Engineering (LandBOSSE) Model

To capture near-future balance-of-systems (BOS) technology innovations, we modified the inputs to the LandBOSSE model to include efficiency gains for alternative erection technologies, reduce foundation masses because of advances in load reduction and controls, and decrease turbine spacing resulting from wake steering, which reduces road and collection system costs. In all cases, we assume a 200-MW plant size and 12 months to complete the BOS scope. The new scaling relationships for LandBOSSE inputs are described as follows:

- Alternative erection technologies: For turbine erection, we assume a climbing crane. We assume that the base section of the tower must be installed by a conventional crawler or hydraulic crane. The climbing crane will be installed using its own hoisting systems and will install all remaining tower sections, the nacelle and its components, hub, and each blade. The climbing crane will then climb down the tower and be loaded onto a trailer for transport to another turbine. The main advantage of a climbing crane is the large reduction in the cost to move a crane from one location to another at a much lower cost than a conventional crane that increases with hub height. The climbing crane is assumed to have a 120-t capacity and 200-m hub height maximum and has the same critical wind speeds as an equivalent crawler crane, 9 meters per second (m/s). We assume that the hoist speed is lower than that of a conventional crane, 10 m/s and 20 m/s, respectively. The travel speed is assumed to be 20 miles per hour, which reflects the speed of a truck and trailer. We assume a crew size of 12, which includes truck drivers, crane operators, oilers, forepersons, and ironworkers. We assume an hourly rate of $450 for the crane itself and an $80,000 mobilization fee.

[18] https://liftra.com/product/lt1500-liftra-installation-crane/
[19] https://www.nrel.gov/docs/fy23osti/81664.pdf

- Foundation scaling: For the 2021 scenario, we assume mass and load scaling relationships for foundations based on empirical foundation designs from 2.5 MW to 5.5 MW. In the 2030 scenario, we assume advances in foundation design and load reductions, resulting in lower concrete and reinforcement steel costs. These estimates of load reductions from advanced turbine controls are difficult to quantify, but we assumed an 8% reduction in foundation concrete and reinforcement steel based on emerging technologies.[20, 21, 22]

- Turbine spacing: For the 2030 scenario, we assume wake steering and advanced controls, which are typically expressed as a change in energy production assuming fixed turbine locations. We assume that wake steering and plant controls can be used to reduce relative turbine spacing while roughly preserving annual energy production (AEP).[23] We assume a capacity density of 4 MW/km^2 in the 2030 case and assess the unitless multiplier used for row and turbine spacing (S) for LandBOSSE using the following equation:

$$S = \frac{1000\text{ m}}{1\text{ km}} \frac{1}{D} \sqrt{\frac{TR}{4\text{ MW/km}^2}} \quad (1)$$

  where D is the rotor diameter in m and TR is the turbine rating in MW. This results in variations in relative spacing across the four turbines as rotor diameter and turbine ratings vary across turbines.

[20] https://www.cte-wind.com/us/2020/07/06/soft-spot-foundation-5-2/
[21] https://www.rutefoundations.com/bxgproducts
[22] https://www.anker-foundations.com/en/wind-turbine-foundation/
[23] In 2021, we assumed that all turbines would use a 10.2 by 10.2 rotor diameter (D), which is representative of an average rotor spacing for 2014–2020 projects in the United States (the average capacity density of this same data set is 2.4 MW/km^2).

Table A-2. Cost and Scaling Relationships in 2021 and 2030

Component	Component Mass Scaling Relationship in 2021[a]	Component Mass Scaling Relationship in 2030[b]
Rotor		
Single Blade	$8.3612 * \left(\frac{D}{2}\right)^2 - 620.03 * \left(\frac{D}{2}\right) + 17{,}847$	$5.5 * \left(\frac{D}{2}\right)^2 - 261.4 * \left(\frac{D}{2}\right) + 6{,}073$
Hub and Pitch System	$8{,}104.7 * TR^{1.1377}$	$38{,}495 * \ln(TR) - 13{,}413$
Nose Cone	$2.3255 * D + 204.65$	$2.3255 * D + 204.65$
Drivetrain and Nacelle		
Low-Speed Shaft	$2.1906 * D^2 - 311.15 * D + 13{,}108$	$2.1906 * D^2 - 311.15 * D + 13{,}108$
Main Bearing(s)	$N_{bearings} * 0.0001 * D^{3.5}$	$N_{bearings} * 0.0001 * D^{3.5}$
Gearbox	$\frac{T}{132.5}$	$\frac{T}{200}$
Braking System	$198.51 * TR + 1.893$	$198.51 * TR + 1.893$
Generator	$1{,}673.1 * TR + 3{,}932.7$	$0.7505(1673.1 * TR + 3{,}932.7)$
Transformer & Power Electronics	$1{,}915 * TR + 1{,}910$	$1{,}915 * TR + 1{,}910$
Yaw System	$1.6(0.0007 * D^{3.1571})$	$1.6(0.0007 * D^{3.1571})$
Bedplate	$737.88 * D - 68{,}066$	$737.88 * D - 68{,}066$
Other: Railing/Platform	$0.005 * M_{bedplate}$	$0.005 * M_{bedplate}$
Other: Crane	$0.005 * M_{bedplate}$	$0.005 * M_{bedplate}$
Other: High-Voltage Alternating Current	$74 * TR$	$74 * TR$
Other: Nacelle Cover	$1281.7 * TR + 428.19$	$1281.7 * TR + 428.19$
Other: Controls	Cost only, not mass; $23{,}249 * TR$	Cost only, not mass; $23{,}249 * TR$
Other: Electrical Connections	Cost only, not mass; $3{,}000 * TR$	Cost only, not mass; $3{,}000 * TR$

Abbreviations: D = rotor diameter in meters; TR = turbine rating in megawatts; $N_{bearings}$ = number of bearings; T = rotor torque in Newtons; $M_{bedplate}$ = mass of the bedplate in kilograms.

a) 2021 Cost and scaling relationships are based on documentation from turbine manufacturers for International Electrotechnical Commission Class 2 and 3 turbine components masses. The turbine drivetrain is a high-speed generator. Blade mass is reflective of blades that contain ~10%–15% carbon by mass. We assume a max tip speed of 88 m/s and maximum drivetrain efficiency of 90%, which are used in sizing the gearbox and other drivetrain components. Towers are assumed to be conventional transportable steel towers.

b) 2030 Cost and scaling relationships are based on 2021 scaling relationships with innovations applied. Blade cost includes cost of blade and segmentation joint at 75% span. We assume a high-speed generator with an integrated drivetrain, which reduces overall drivetrain mass. We assume that an integrated drivetrain reduces drivetrain component masses and length, further reducing nacelle bedplate mass. We assume reduced generator mass based on work from Wood Mackenzie and others. Gearboxes are assumed to have a torque density of 200 Newton-meters per kilogram. We assume a maximum tip speed of 88 m/s and maximum drivetrain efficiency of 90%, which are used in sizing the gearbox and other drivetrain components. Tower mass scaling assumes spiral-welded towers built in factory for hub heights less than 110 m and unconstrained base diameter towers for hub heights greater than 110 m.

Breakdown of Capital Costs

We used our cost modeling method to estimate the capital costs for each of the four modeled turbines. Figures A-1, A-2, and A-3 shows how total capital costs, turbine component and transport costs, and balance-of-systems costs, respectively, differ for each of the turbines in all three cost scenarios in 2021 and the Moderate scenario in 2030.

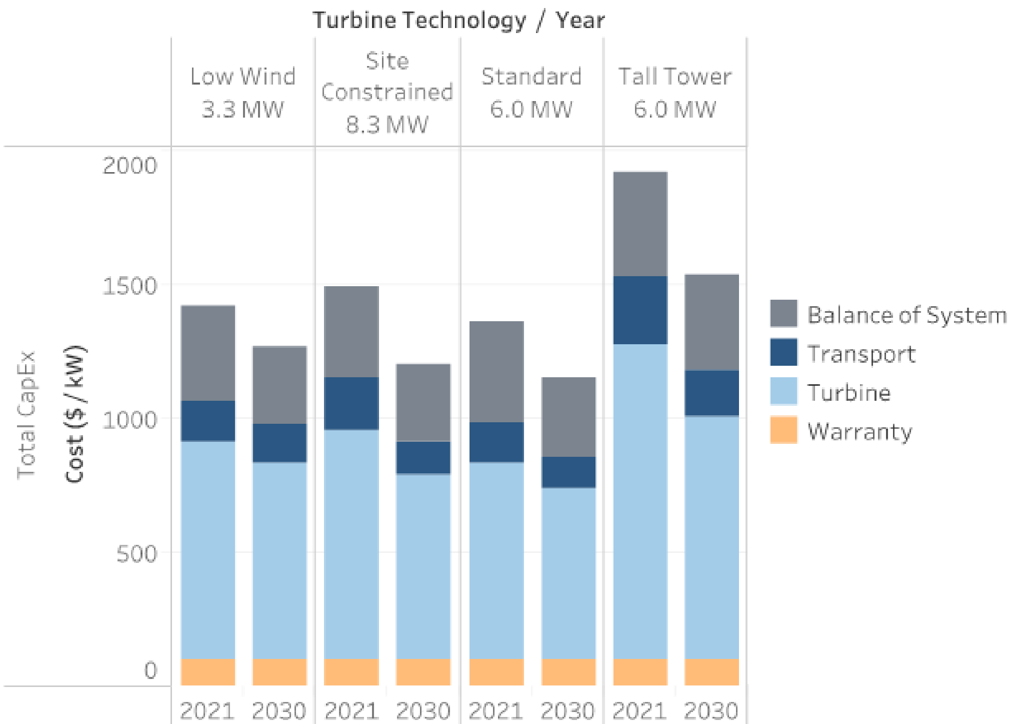

Figure A-1. Total capital expenditures (CapEx) by category for all three cost scenarios (Conservative, Moderate, and Advanced) in 2021 and Moderate scenario in 2030

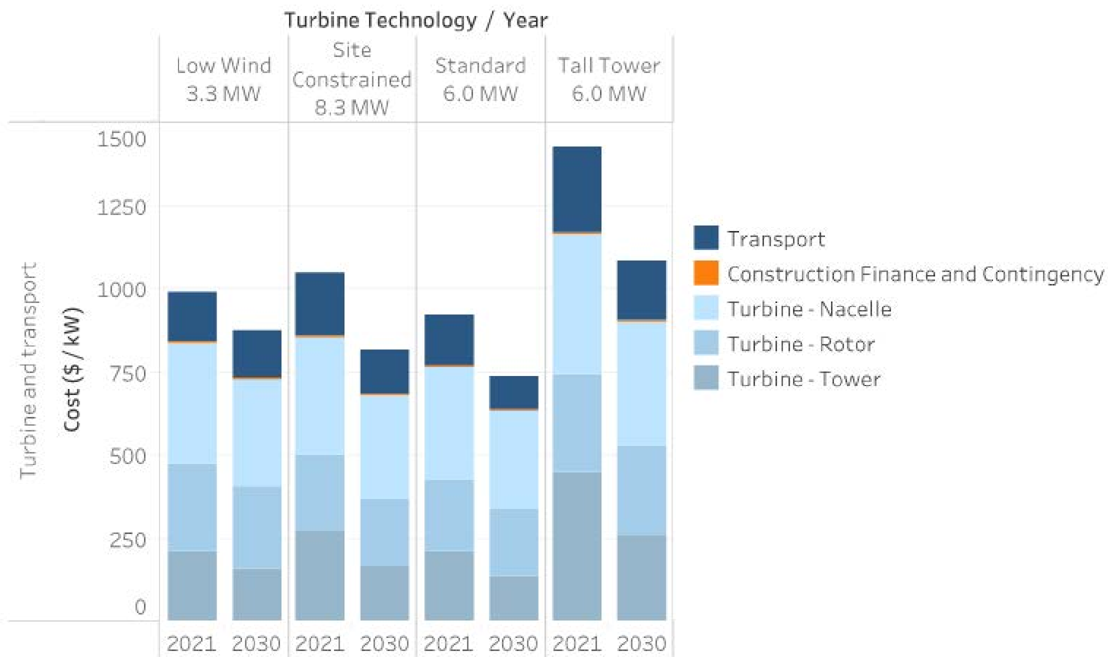

Figure A-2. Turbine component and transport costs for all three cost scenarios (Conservative, Moderate, and Advanced Scenarios) in 2021 and Moderate scenario in 2030

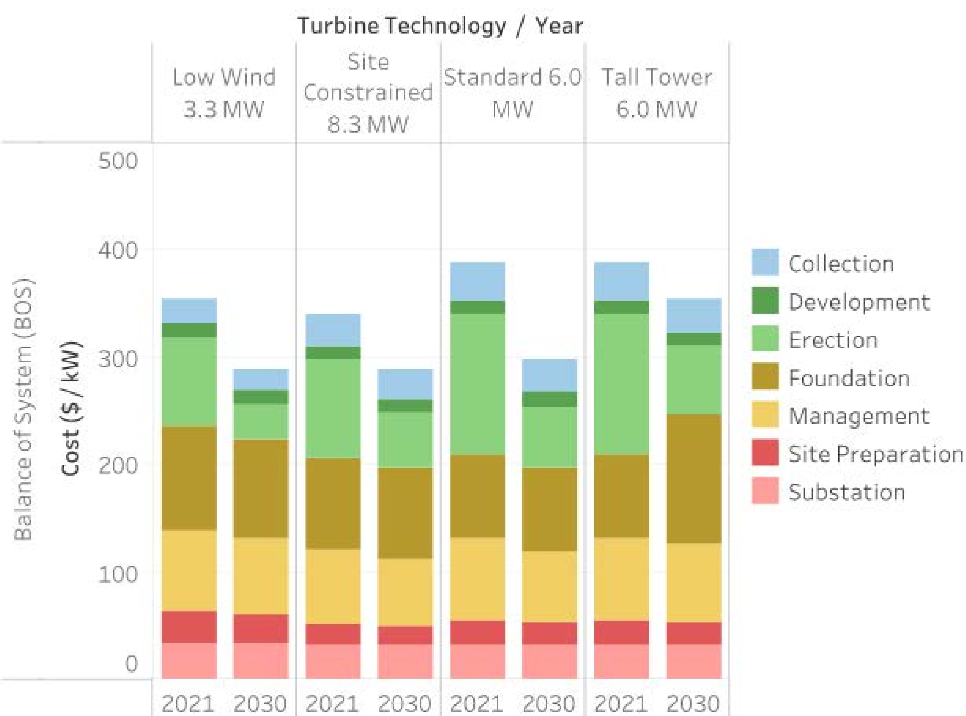

Figure A-3. BOS cost contributions for all three cost scenarios (Conservative, Moderate and Advanced) in 2021 and Moderate scenario in 2030

Details on Geospatial Supply Curve Modeling

The wind layout optimization method uses the Park (Jensen) wake model and the cost vs. capacity function to meet the objective function. Typically, as turbine spacing decreases, wake losses increase. However, as plant capacity increases, the cost per unit of capacity decreases because of economies of scale in many areas. This trend is observed empirically with a 58% reduction in installed project cost between projects less than 5 MW of capacity and greater than 200 MW of capacity (Wiser et al. 2021). The optimization approach used in reV explicitly places turbines in the available area after setbacks and exclusions are applied. The resulting plant layout is passed to the System Advisor Model (Blair et al. 2018), which computes wake loss-adjusted generation values. The total annual generation for the plant layout is used to compute the LCOE. A genetic algorithm with a population size of 25 (i.e., 25 plant layouts mutating simultaneously) optimizes the resulting LCOE values in a few hundred iterations by adding/removing turbines in each layout between iterations.

The optimization does not consider costs associated with increasing relative rotor spacing. These costs empirically include increased collection system cable length, increased road length, and increased land lease payments to landowners. Previous research shows that including a function to account for these costs as a function of turbine spacing may increase plant capacity density and decrease the total plant capacity in our optimization (Stevens 2016). The optimization is constrained by spatial setbacks and exclusions that determine locations where turbines are allowed or not allowed to be placed. Because the optimization explicitly sites turbines around complex exclusion geometry and considers individual turbine installed cost functions and wake losses, the turbine resulting in the lowest LCOE value for a single site may not be the turbine with the lowest LCOE value calculated only by annual average wind speed for a single turbine.

As mentioned in the main text, our composite supply curve comprises the least-cost turbine at each location including wind speed thresholds. The supply curve comparisons of each turbine (without wind speed thresholds) versus the composite is shown in Figure 5. Figure A-4 illustrates how the composite supply curve compares to the supply curves of the individual turbines with wind speed thresholds.

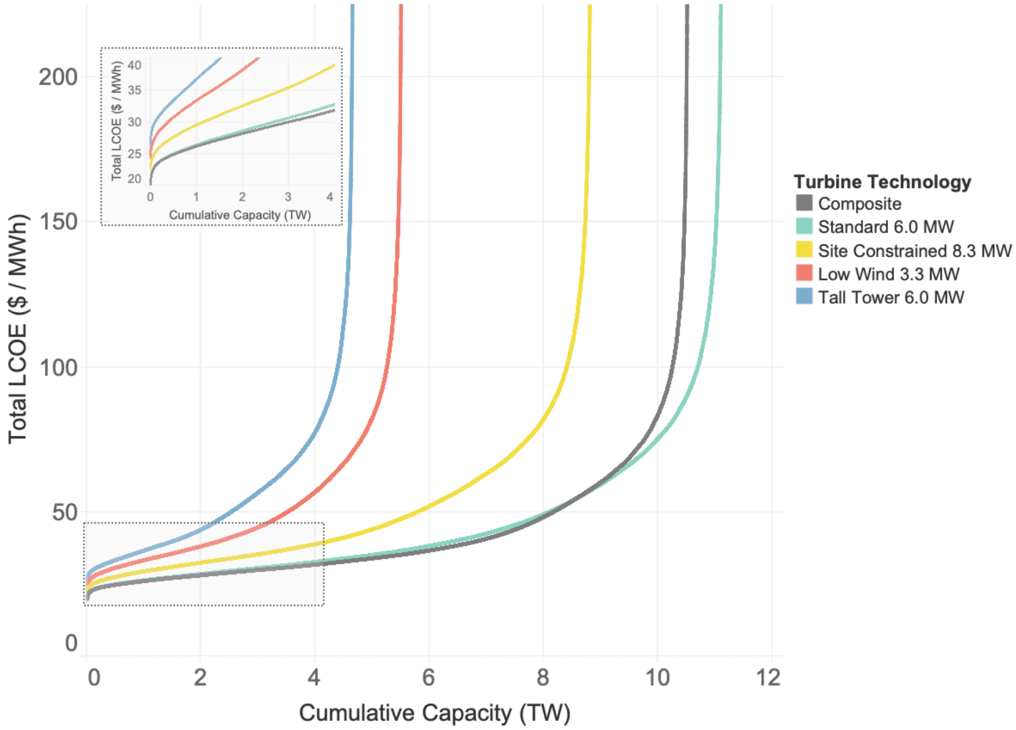

Figure A-4. Supply curves for each individual turbine (including wind speed thresholds) compared to the composite (including wind speed thresholds) for the Moderate turbine cost scenario in 2030.

The inlay shows how the supply curves differ at lower cumulative capacities (from 0 TW to 4 TW). As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m D; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.

Supplemental Figure for Power Sector Modeling Results

Figure 13 and Table 5 illustrate how the power sector performance metrics vary for each of our scenarios. Figure A-5 provides more details about the differences in system cost.

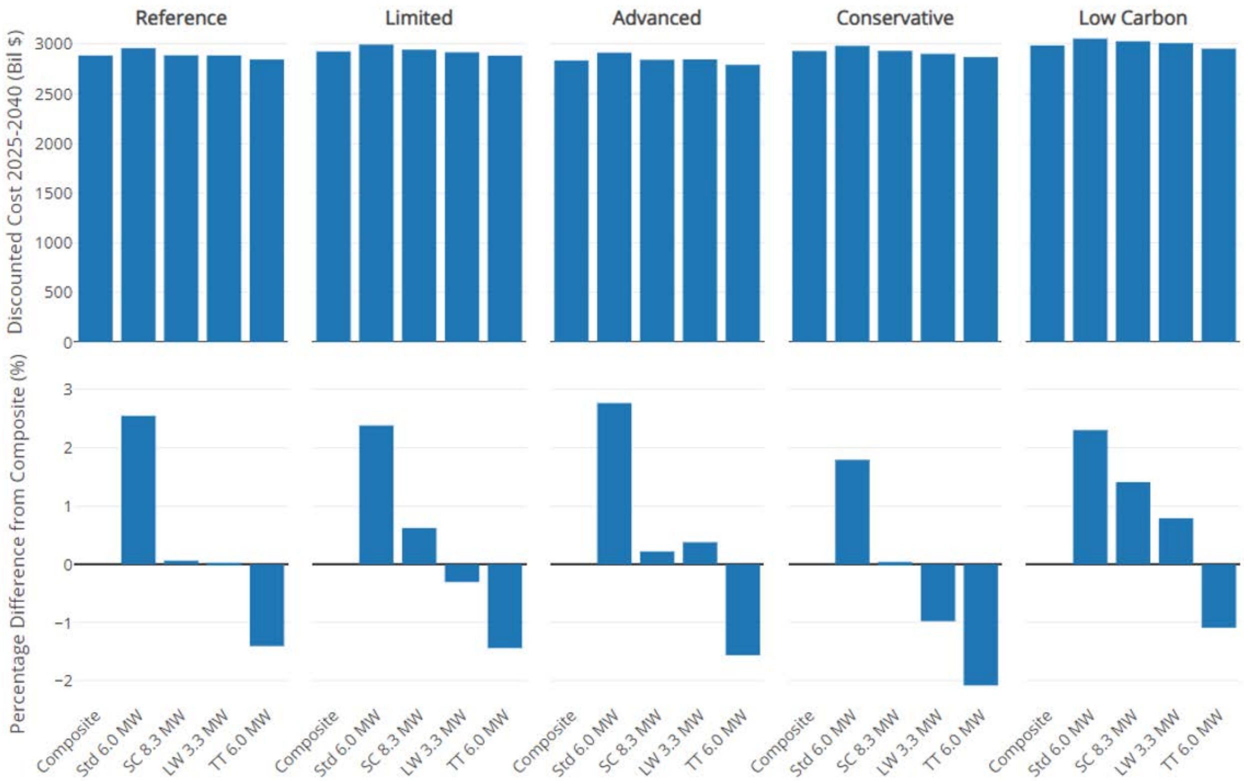

Figure A-5. Discounted cost (top row) and differences in discounted cost compared to the composite (bottom row) for single wind turbine technologies and the composite from 2025 to 2040

Abbreviations: Std = Standard; SC = Site Constrained; LW = Low Wind; TT = Tall Tower. As described in Section 2.1, Standard 6.0 MW has a 6.0-MW turbine rating (TR), 115-m hub height (HH), and 170-m rotor diameter (D); Site Constrained 8.3 MW has an 8.3-MW TR, 130-m HH, and 196-m RD; Low Wind 3.3 MW has a 3.3-MW TR, 100-m HH, and 148-m D; Tall Tower 6.0 MW has a 6.0-MW TR, 140-m HH, and 196-m D.